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ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1984

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ERCB DECISIONS 1984

Many Islands Pipelines (Canada) Limited
Pre-hearing meeting
Memorandum of Decision

New Facilities at the Syncrude Mildred Lake Oil Sands Plant
Pre-hearing Meeting
Memorandum of Decision

ERCB INQUIRY REQUIREMENTS FOR MAJOR ELECTRIC TRANSMISSION LINES IN THE EDMONTON AREA

ERCB D 84-1 Feb 1984

Report reviews requirements for future major electric transmission lines needed to supply electric energy in the Edmonton area.

Report contains the scope and the need for the inquiry; views of the participants regarding the need for and feasibility of future development; review of electric load forecast; identification of constraints; criteria for evaluating and selecting facilities; requirements and alignments for future corridors.

ESSO CANADA RESOURCES LIMITED LEDUC-WOODBEND D-3 A POOL CONCURRENT PRODUCTION SCHEME GOLDEN SPIKE GAS STORAGE SCHEME

ERCB D 84-2 Jan 1984

Deals with application by Esso Canada Resources Limited for blowdown of main pool and concurrent production of saddle and south-east extension areas of Leduc-Woodbend D-3 A pool; also deals with application by Esso Canada Resources Limited for storage of Leduc-Woodbend D-3 A pool gas in the Golden Spike D-3 A pool.

Report contains background of pools on Cooking Lake aquifer chain; oil in place and oil recovery from Leduc-Woodbend D-3 A pool; gas recovery from Leduc-Woodbend D-3 A pool; effect of blowdown scheme on non-unit owners in Leduc-Woodbend D-3 A pool; effect of blowdown on nearby pools; effects of gas markets on scheme implementation; benefits of scheme.

WESTERN DECALTA PETROLEUM (1977) LIMITED DIAMOND VALLEY GAS PROJECT TURNER VALLEY FIELD AND AREA

ERCB D 84-3 Mar 1984

Deals with application by Western Decalta Petroleum (1977) imited for approval to construct gas processing plant in artell area south of Turner Valley.

Discusses need for Diamond Valley gas plant; appropriate location and size of gas plant; effect of gas plant on surrounding area.

GASCAN RESOURCES LTD. ENHANCED RECOVERY MITSUE GILWOOD A POOL CHEVRON CANADA RESOURCES LIMITED AMENDMENT TO BOARD APPROVAL 3665 ENHANCED RECOVERY MITSUE GILWOOD A POOL

ERCB D 84-4 Apr 1984

Deals with application by Gascan Resources Ltd. for approval of two schemes for enhanced recovery of oil by water injection in the Mitsue Gilwood A pool; also deals with application by Chevron Canada Resources Limited for amendment to Approval 3665 to permit conversion of well, Atlantic Mitsue 2-22-69-3 W5M, to fresh water injection service.

Report contains need for consideration of project status; need for voidage replacement to enhance oil recovery; effectiveness of communication between injector and producing wells; ability to control performance of wells in schemes; possible proliferation of similar scheme and potential impact on pool recovery; opportunity of each operator to obtain its share of production from pool; controls for performance monitoring.

LODGEPOLE BLOWOUT INQUIRY - PHASE 2 SOUR GAS WELL BLOWOUTS IN ALBERTA; THEIR CAUSES AND ACTIONS REQUIRED TO MINIMIZE THEIR FUTURE OCCURRENCE

ERCB D 84-5 Apr 1984 N/C

Inquiry to report on causative factors of sour gas blowouts in Alberta, and actions that can reasonably be taken to minimize possibility of future occurrences.

Discusses well blowouts in Alberta; early formation of a blowout prevention review committee (BPRC) to examine drilling practices, on-site supervision and equipment and rig inspection procedures; development of special drilling precautions and blowout prevention controls to be used on all wells designated by the ERCB as "critical"; need for improved and increased training for those directly involved in sour well drilling; involvement of public in development of emergency response plans for drilling of "critical" sour wells.

ESSO RESOURCES CANADA LIMITED QUIRK CREEK GAS PROCESSING PLANT

ERCB D 84-6 Apr 1984 $ 5

Deals with application for approval to process sour gas reserves from Moose and Whiskey fields at the Quirk Creek plant.

Discusses background on initial application by Esso in 1981; recent approval of Moose/Whiskey pipeline system; environmental impact aspects; additional gas recovery from Quirk Creek field; sulphur recovery efficiency; summary and decision.

CANTERRA ENERGY LTD. SOUR GAS PIPELINE FUEL GAS PIPELINE CALGARY AREA

ERCB D 84-7 May 1984 $ 5

Deals with applications by Canterra for permits to construct pipelines to gather sour gas from and deliver fuel gas to wells in the Okotoks field.

Discusses purpose and necessity of proposed pipelines including appropriateness of a limited time period for any appoval; route and sour gas level of proposed pipelines; need for special permit conditions; pipeline design; sour gas-related land-use planning constraints.

AMOCO CANADA PETROLEUM COMPANY LTD. APPLICATION FOR A WELL LICENCE

ERCB D 84-8 Apr 1984 $ 5

Deals with application by Amoco Canada Petroleum Company Ltd. for well licence for proposed well to be known as Amoco Stal A6-6-54-25, located in Legal Subdivision 6 of Section 6, Township 54, Range 25, West of the 4th Meridian.

Discusses need for the well; maximum hydrogen sulphide (H_2S) release rate that could be expected should a blowout occur; safety of the public.

LODGEPOLE BLOWOUT INQUIRY - PHASE 1

ERCB D 84-9 Dec 1984 N/C

Inquiry into events and circumstances leading up to, and the cause of, a sour gas well blowout on 17 October 1982, near Lodgepole, Alberta and the events following the blowout.

Discusses cause of blowout and adequacy of actions taken by Amoco Canada Petroleum Company Ltd. to prevent it; well-control activities and adequacy of actions by Amoco and others; hazard to human health; impact on environment and on personal property; communication and co-ordination; adequacy of ERCB responses following blowout, and its regulations, policy, and procedure; adequacy of govn't. departments' responses following the blowout, and their regulations, policy, and procedure; significance of inquiry recommendations in reducing potential for blowouts; developments since release of Phase 2 report.

ADDENDUM TO ERCB D 84-9 (LODGEPOLE BLOWOUT INQUIRY - PHASE 1)

Dec 1984 N/C

An addendum to report upon additional information with respect to the flow rate of the well, Amoco Dome Brazeau River 13-12-48-12. Addendum includes recent data from testing of the well; the impact of the data on the findings and recommendations of ERCB D 84-9.

ALBERTA ENERGY COMPANY LTD. PROPOSED PIPELINES AND RELATED FACILITIES COLD LAKE - EDMONTON AREAS

ERCB D 84-10 Jun 1984 $ 5

Deals with Alberta Energy proposed pipelines and related facilities to transport increased volumes of diluent from Edmonton to Cold Lake area and blended bitumen from Cold Lake area to Edmonton.

Discusses purpose and necessity of proposed pipelines; pipeline route; environmental impacts; agricultural impacts; crossing of Genstar lands; pipeline design, construction, and operation.

WESTMIN RESOURCES LIMITED RATEABLE TAKE LINDBERGH COLONY W POOL

ERCB D 84-11 May 1984 $ 5

Deals with application for declaration to restrict amount of gas produced from Lindbergh Colony W Pool by distributing amount of gas that may be produced from pool in equitable manner among wells in the pool.

Discusses need for a rateable-take order; basis for distributing production between wells in the pool; effective date of rateable-take order.

WIND-POWERED ELECTRIC GENERATOR OF A. E. SINNOTT NEAR PINCHER CREEK

ERCB D 84-12 Jun 1984 $ 5

Deals with application for approval to operate a 40-kilowatt wind-powered electric generator in Pincher Creek area and to connect generator to the electric distribution system of TransAlta Utilities Corporation.

Disusses effects of the wind-powered generator on Alberta electric system; banking of surplus energy from the wind-powered generator in TransAlata's electric system; the value of surplus energy; a trial period for gathering technical and cost information; some general principles applied by the Board in dealing with the application.

ENHANCED RECOVERY PEMBINA NISKU N POOL CANADIAN RESERVE OIL AND GAS LTD. TEXACO CANADA RESOURCES LTD.

ERCB D 84-13 Jun 1984 $ 5

Deals with application by Canadian Reserve Oil and Gas Ltd. and BP Exploration Canada Limited for an enhanced recovery scheme by water injection in a portion of the Pembina Nisku N pool; also deals with application by Texaco Canada Resources Ltd. for an enhanced recovery scheme by hydrocarbon miscible flood in the Pembina Nisku N pool.

Discusses background of Pembina Nisku N pool; oil recovery and pool performance under waterflood and miscible flood; associated economics of each depletion scenario.

APPLICATION BY ESSO PETROLEUM CANADA, A DIVISION OF IMPERIAL OIL LIMITED TO AMEND ERCB APPROVAL HE 8208

ERCB D 84-14 Jun 1984 $ 5

Deals with application by Esso Petroleum Canada to alter the electric distribution system and service area boundary of the City of Edmonton (Edmonton Power).

Discusses ERCB Approval HE 8208 which designates electric service area boundary of Edmonton Power to coincide with municipal boundary of City of Edmonton; issue of electric service to Esso's Strathcona refinery complex being provided by both Edmonton Power and TransAlta Utilities Corporation because part of the complex is within the limits of the City of Edmonton and part outside the city limits; effect on cost of electric service to Esso due to being served by two utilities; suggested ways of resolving the issue of Esso being faced with higher cost of service as result of being served by two utilities.

ADDENDUM TO ERCB D 84-14

Jan 1984 $ 5

Deals with application by Esso Petroleum Canada to alter electric distribution system and service area boundary of the City of Edmonton (Edmonton Power).

Discusses ERCB Approval HE 8208 which designates the electric service area boundary of Edmonton Power to coincide with municipal boundary of City of Edmonton; issue of electric service to Esso's Strathcona refinery complex; increase in cost of electric service to Esso due to being served by two utilities; Board decision.

LOCAL INTERVENERS' COSTS RESPECTING THE 240-KV TRANSMISSION LINE FOR THE LANGDON SUBSTATION TO ANDERSON SUBSTATION

ERCB D 84-15 Jun 1984 N/C

Deals with local interveners' costs applications resulting from a hearing which commenced 6 March 1984 in Strathmore and was adjourned 14 March 1984, sine die.

Discusses interveners' claims for an advance of costs; appropriateness of cost applications prior to completion of hearing; need for advance of costs to interveners.

ESSO RESOURCES CANADA LIMITED APPLICATION TO PROCEED WITH PHASES III AND IV OF THE COLD LAKE PROJECT

ERCB D 84-16 Jun 1984 $ 5

Deals with application for approval of immediate development of Phases III and IV which would produce an additional 3000 cubic metres per day of crude bitumen.

Discusses summary of details for Phases III and IV; biophysical environmental impacts; use of Cold Lake as source of fresh water make-up; socio-economic impacts; decision.

NORTHWESTERN UTILITIES LIMITED PIPELINE UPGRADING AT ROAD CROSSINGS COUNTY OF LAC ST. ANNE

ERCB D 84-17 Jun 1984 $ 5

Deals with application by Northwestern Utilities Limited for approval to upgrade its Swan Hills gas transmission pipeline at road crossings in the county of Lac St. Anne.

Discusses purpose and necessity of upgrading the pipeline; reasonableness of conditions imposed by county on granting of approval to case road crossings.

ZAHAVA HANEN AND RUMSEY RANCHES' REQUEST FOR LOCAL INTERVENERS' COSTS RE: ESSO QUIRK CREEK GAS PLANT

ERCB D 84-18 Jul 1984 N/C

Deals with local interveners' costs applications resulting from hearing on Application No. 830698 - Esso Quirk Creek gas plant.

Discusses appropriateness of costs claimed for the expert testimony presented at the hearing.

BRAZEAU RIVER NISKU CARBONATE BANK OPTIMUM DEPLETION INQUIRY AMOCO CANADA PETROLEUM COMPANY LTD.

MEMORANDUM OF DECISION AND
ERCB D 84-19 Jul 1984 $ 5

Deals with an inquiry by the Board into optimun depletion strategy for recovery of hydrocarbon from gas reservoirs in Brazeau River Nisku Carbonate Bank; applications by Amoco Canada Petroleum Company Ltd. for scheme of gas cycling and for permits to construct pipelines in Nisku Carbonate Bank area of Brazeau River field.

Discusses proposed flow and pressure monitoring program; adjournment of inquiry; approval of pipelines.

BANKENO RESOURCES LTD. APPLICATION FOR APPROVAL OF A GAS PROCESSING PLANT MORINVILLE FIELD

ERCB D 84-20 Sep 1984 $ 5

Deals with application by Bankeno Resources Ltd. for approval to construct and operate a sour gas processing plant in the Morinville field.

Report discusses the need for the gas plant; the appropriate location and size of the gas plant; effect of gas plant on surrounding area.

SOCIÉTÉ QUÉBÉCOISE D'INITIATIVES PÉTROLIÈRES (SOQUIP) APPLICATION TO AMEND GAS REMOVAL PERMIT

ERCB D 84-21 Oct 1984 $ 5

Application is for approval to increase the total volume of gas to be removed from Alberta by 5.108 billion cubic metres; increase the annual volume by 340.545 million cubic metres; and increase the maximum daily volume by 933 thousand cubic metres during the period 1 November 1984 to 31 October 1997; approval to extend the permit term from 31 October 1997 to 31 October 1999; approval to name 15 additional fields, pools, and areas from which gas may be obtained for removal from Alberta.

Discusses reserves under contract to SOQUIP; gas surplus; public interest; jurisdictional matters; permit conditions; findings and decision.

FEDERATED PIPE LINES LIMITED PEACE PIPE LINE LIMITED PROPOSED HIGH VAPOUR PRESSURE PIPELINES AND RELATED FACILITIES FORT SASKATCHEWAN TO SWAN HILLS-JUDY CREEK AREA

ERCB D 84-22	Sep 1984	$ 5

Deals with an application by Federated to connect an existing oil pipeline between Namao and Swan Hills to high vapour pressure service and to construct new high vapour pressure pipelines between Fort Saskatchewan and Namao, around the town of Morinville and in the Swan Hills and Judy Creek areas. The pipelines would be used to transport high vapour pressure natural gas liquids from Fort Saskatchewan to proposed miscible flood projects in the Swan Hills and Judy Creek areas; an application by Peace Pipe to construct new high vapour pressure pipelines and related facilities between Fort Saskatchewan and Namao. The pipeline would be laid in a common ditch with Federated's pipeline and would transport high vapour pressure natural gas liquids from Namao to a cavern storage facility in Fort Saskatchewan.

Discusses the adequacy of the selected existing pipeline for the intended high vapour pressure service; the routing of the proposed new pipelines; need for the Namao to Fort Saskatchewan leg of the pipelines.

BIEWAG ENERGY RESOURCES LTD. AMENDMENT OF INDUSTRIAL DEVELOPMENT PERMIT WASKATENAU AREA

ERCB D 84-23	Oct 1984	$ 5

Application is for amendment of dates in Clause 10 of the permit and paragraphs 1 and 2 of Attachment I to O.C. 1129/82, as amended. All dates would be amended to read 30 June 1985.

Report discusses background of project; interveners' views; findings and recommendation.

NEW FACILITIES AT THE SYNCRUDE MILDRED LAKE OIL SANDS PLANT SO_2 EMISSION LIMITS

ERCB D 84-24	Oct 1984	$ 5

Deals with an application to amend Syncrude's existing approval 2959 to increase the yearly synthetic crude oil production, to modify existing equipment and construct new facilities, and to extend the approved life of the project to 31 December 2013.

Discusses the proposed expansion; the extension of the term of project approval by a further 9 years to 31 December 2013; sulphur dioxide and particulate emission; other environmental, social and economic issues.

ADDENDUM TO ERCB D 84-24

Jan 1985 $ 5

Deals with SO_2 emission limits for new facilities at Syncrude Mildred Lake oil sands plant.

Discusses the 90-day rolling average limits and their administration; retention of 292 tonnes/day daily limit; retention of hourly limit of 16.4 tonnes/hour.

MANY ISLANDS PIPELINES (CANADA) LIMITED REQUEST FOR ADDITIONAL RESERVOIR DATA MEDICINE HAT MEDICINE HAT A AND C POOLS

ERCB D 84-25 Oct 1984 $ 5

Application for an order directing the obtaining of certain additional reservoir data in the application area to deal with an equity matter raised concerning the Medicine Hat A and C pools in the Medicine Hat field.

Discusses information before the Board; the need for additional reservoir data.

SHELL CANADA RESOURCES LIMITED PEACE RIVER EXPANSION PROJECT

ERCB D 84-26 Nov 1984 $ 5

Deals with application for approval of a commercial scheme involving the expansion of Shell's current Peace River in situ project.

Report discusses reserves and recovery efficiency; size and phasing of the project; environmental management; water management; field facilities and protection of aquifers; marketing of bitumen; availability of diluent; socio-economic impact; local employment and business opportunities for natives.

PANCANADIAN PETROLEUM LIMITED APPLICATION FOR A WELL LICENCE

ERCB D 84-27 Nov 1984 $ 5

Application for well licence to drill a well in the Gleichen field in Legal Subdivision 16 of Section 33, Township 23, Range 21, West of the 4th Meridian, to obtain production from the Medicine Hat sand.

Report discusses location of proposed well.

A REPORT ON AN APPLICATION BY CANTERRA ENERGY LTD. TO DRILL A CRITICAL SOUR WELL IN THE SUNDRE AREA

ERCB D 84-28	Dec 1984	$ 5

Application to drill a critical sour gas well in Sundre area (12-12-32-6 W5M).

Discusses concerns of area residents; purpose of well and its potential release rate; precautions necessary (drilling) if well were drilled; possibility of drilling problems and well blowout; emergency planning to be used in event of drilling problems or blowout; stringent requirements applied to drilling and emergency planning with specific emphasis on ignition of uncontrolled well flow; test phases and likelihood of further development.

DEVNIC RESOURCES LTD. APPLICATION FOR A WELL LICENCE ACHESON AREA

ERCB D 84-29	Dec 1984	$ 5

Application to drill well (13-18-53-25 W4M) to obtain gas production from Belly River group and oil production from Ellerslie member or Wabamun group.

Discusses need for the well, impact of well during drilling and production phases; mitigative measures taken to reduce impact; future development in area of application.

BRAZEAU RIVER NISKU CARBONATE BANK PRIMARY PRODUCTION AND CYCLING SCHEME

ERCB D 84-30 (Interim Decision)	Dec 1984	$ 5

Application for scheme of gas cycling in a portion of the Carbonate bank.

Discusses dewpoint pressures for reservoir fluids; primary production; gas cycling.

PALMER RANCH (1984) LTD. INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA

ERCB D 84-31	Jan 1985	$ 5

An application for approval to use natural gas as raw material and fuel in production of anhydrous ammonia in a new plant to be constructed on site of decommissioned Pincher Creek gas plant.

Discusses need for the plant; gas supply; efficient use of gas; environmental impacts; economic costs and benefits.

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

MANY ISLANDS PIPELINES (CANADA) LIMITED
PRE-HEARING MEETING

Memorandum of Decision
Application 840297

1 INTRODUCTION

The Board has before it a matter which may affect owners of the Medicine Hat A and C pools in parts of townships 12, 13, 14, and 15, ranges 1, 2, 3, and 4, west of the 4th meridian, of the Medicine Hat Field, and may have relevance to owners outside the aforementioned area.

1.1 The Application

Many Islands Pipelines (Canada) Limited (Many Islands) submitted an application to the Board which raises an equity matter in a 7-township area of the Medicine Hat Field. Many Islands holds the natural gas rights to the Medicine Hat A zone in the area of application. It contends that hydraulic fracturing during well stimulation of the underlying Medicine Hat C zone wells has resulted in communication between the C and A zones, and that the C zone wells are draining some of the A zone gas reserves.

1.2 Reasons for Pre-Hearing Meeting

The Board called a pre-hearing meeting respecting the application because:

- the application does not explicitly state what remedy is requested and additionally, it makes reference to several statutory provisions,
- the application makes reference to the need for additional reservoir information which would lead to a better technical understanding of the problem,
- the Board received a letter from the major C zone owners; Merland Exploration Limited, Bralorne Resources Limited, and Gascan Resources Ltd. (Merland et al), which indicated that certain studies are underway which should be completed before a resolution of the problem is attempted, and
- the Board recognized a need to consider how and when to proceed with the various aspects of the application.

1.3 The Pre-Hearing Meeting

A pre-hearing meeting was held on 9 May 1984 with G. J. DeSorcy, P.Eng., N. Strom, P.Eng., and L. A. Bellows, P.Eng., sitting.

Those who appeared at the meeting were: Many Islands represented by W. T. Corbett and S. R. Miller and presenting Messrs J. D. MacGowan, P.Eng. and I. Martin, P.Eng. as witnesses; Merland et al represented by A. L. McLarty; TransCanada PipeLines Limited (TransCanada) represented by E.W.H. Mallabone and P. J. Raina, P.Eng.; and Energy Resources Conservation Board staff represented by M. J. Bruni, H. R. Keushnig, P.Eng., and A. Warren, P.Eng.

2 AGENDA

An agenda for the meeting, proposed by the Board and agreed to by the participants, included the following items:

- an attempt to clarify the application, particularly with respect to the remedy being sought and the legislation under which it is being requested,
- a discussion of the need for further information, the amount of that information which is now available, and the time of the availability of other relevant information,
- a discussion of the appropriate timing of a hearing, if necessary, to consider the matter, and
- a discussion of any other matters of a procedural nature which can properly be handled at this time.

The summary position of each participant concerning agenda items are presented in the following sections. The Board's views and decision follow those of the participants.

3 VIEWS OF MANY ISLANDS

Many Islands divided its application into two parts:

(1) a request of the Board to help obtain additional field performance data to ascertain the degree of drainage with greater certainty, and

(2) a request of the Board to assist in the determination of an equitable solution to the alleged drainage problem.

Many Islands intentionally applied under both general and specific provisions of the legislation because the equity matter it raised is unique and it held that the Board should be afforded the widest possible flexibility to deal with the complex matter.

Many Islands indicated that it was prepared to proceed to a hearing on the basis of the application as submitted. However, it said that a better resolution of the matter could ultimately be made by the Board if additional pressure data on some 100 C zone wells were available. Many Islands suggested that the Board can order the gathering of this data, should the Board deem it appropriate, without further consulting the C zone owners. Many Islands made it clear that part of its application was a request that the Board order the taking of such pressure data. It said that the Board should also order the gathering of any other information it believed would assist in a resolution of the matter. Should the Board decide to order the gathering of additional data, Many Islands suggested an August or September 1984 hearing date, otherwise it prefered a mid-June 1984 hearing date. Many Islands requested that the Board make it clear that any order eventually issued would be retroactive to the date of application. If this was assured by the Board, Many Islands said it would be receptive to any reasonable hearing date, such as in November 1984.

3.1 Views of Merland et al

Merland et al contended that the application has essentially three parts:

(1) a request of the Board to direct the obtaining of data,

(2) a determination of the existence, direction, and extent of gas migration, and

(3) the determination of an equitable solution of the problem, if warranted.

It further contended that the application is deficient until all parties that might be adversely affected are provided with a clear statement by Many Islands of what is being applied for.

Although Merland et al offered November 1984 as the earliest possible time for the commencement of a hearing on the second part of the application, it suggested that establishing the timing of such a hearing should follow a decision on the gathering of additional data. On the question of additional data, Merland et al stated that it required a detailed written description of the data being requested of each company and a reasonable opportunity to respond.

3.2 Views of TransCanada

TransCanada stated that it could take no position until the application was made more specific. It advised that it would need 30 to 90 days following the submission of all data to prepare for a hearing.

3.3 Views of the Board

The Board is satisfied that it has the jurisdiction to deal with equity matters such as are raised by Many Islands in its application. However, it would not proceed to a hearing of that aspect of the application without further clarification by Many Islands as to the specific action it is requesting of the Board.

The Board agrees with the participants that the question of the need for additional data should be handled first before considering the timing of subsequent hearing(s) on the remainder of the application. In this regard, the Board does not agree with Many Islands that a Board direction to gather the additional data requested in the application could not affect the rights of the C zone owners. For this reason, it believes that each of the owners, and any other parties with a direct interest in the matter, should be given the opportunities provided by section 29 of the Energy Resources Conservation Act, to learn of the application and make representations respecting it. To allow this, the Board is prepared to schedule a hearing for 19 June 1984 to consider the Many Islands request that the Board order "that reservoir pressures be obtained for C zone wells which are currently producing over 2.8×10^3 m^3 per day (100 Mcf per day) as soon as reasonably possible." (Requested action (2) on page 4 of the Many Islands application.) A notice will be issued in a few days calling for submissions on the matter to be filed with the Board by 12 June 1984.

Although the Board is scheduling a hearing to consider the request for additional data, it recognizes that the involved parties may, prior to the date of the hearing, agree on the need or otherwise for more data. The Board encourages negotiations towards such an agreement, and if one is reached, would cancel the 19 June hearing. The Board also recognizes that Many Islands could negate the need for a hearing by withdrawing the above mentioned action (2) of its application.

The Board has some question concerning the legality of making retroactive any Board decision on resolution of any drainage problem which might be found, as was contemplated by Many Islands. However, it believes that it would be inappropriate to address the matter at this time.

DATED at Calgary, Alberta on 15 May 1984.

ENERGY RESOURCES CONSERVATION BOARD

GJ DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

N Strom

N. Strom, P.Eng.
Board Member

LA Bellows

L. A. Bellows, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

NEW FACILITIES AT THE SYNCRUDE
MILDRED LAKE OIL SANDS PLANT

Memorandum of Decision
Pre-hearing Meeting
Application 840142

1 INTRODUCTION

On 9 February 1984, the Energy Resources Conservation Board (Board) received an application from Syncrude Canada Ltd. (Syncrude) to increase the approved yearly synthetic crude oil production at its Mildred Lake facility from 7 507 000 cubic meters to 8 000 000 cubic meters, through equipment modifications and additions, and to extend the approved life of the project to 31 December 2013. Chief Dorothy McDonald of the Fort McKay Indian Band (Band) submitted a request to the Board for additional environmental information from Syncrude and Suncor Inc. (Suncor), and for the opportunity to present the Band's intervention to the hearing in Fort McKay. As a result of the Band's request, a pre-hearing meeting was held on 15 June 1984 in Fort McMurray to discuss the following:

(a) where the intervention of the Band will be presented,

(b) if additional information, as requested by the Band, needs to be filed,

(c) the date for filing of the information referred to in clause (b), if it is found to be relevant, and

(d) any other matters relevant to consideration of the application.

The panel members were V. Millard, Panel Chairman, N. Strom, P.Eng., and V. Bohme, P.Eng.

The participants who registered at the meeting are shown in Appendix 1.

2. Participants' Views

2.1 The Fort McKay Indian Band

The Band contended that:

(a) Its intervention should be heard in Fort McKay so that the Board can hear evidence from the entire community, many members of which otherwise could or would not attend due to age or unwillingness to participate in a hearing in unfamiliar surroundings.

(b) Additional detailed performance and design data relating to the existing process units and proposed emission control equipment should be provided by Syncrude. This base process information, that was not released because it was considered by Syncrude to be proprietary, is necessary to do a thorough environmental impact assessment.

(c) Additional environmental monitoring information should be provided by Syncrude and Suncor because:

   (i) it is needed to develop baseline data of the current situation which is necessary in order to assess whether the expanded operations could have an environmental impact,

   (ii) the environmental impact statements provided in the application are general and speculative in nature. The data required to support the statements are normally part of an Environmental Impact Assessment, which is a requirement under ERCB Guide-23, "Guidelines Respecting An Application For A Commercial Crude Bitumen Recovery and Upgrading Project.", and

   (iii) both the Syncrude and Suncor environmental operations need to be reviewed since it is the total emissions that affect the environment of the area and the health of nearby residents.

(d) A legal opinion by the Alberta Environmental Law Centre argued that the Board does have statutory jurisdiction to consider health matters in both hearings related to specific approval applications and in general inquiries.

(e) A two-stage process for the current Syncrude application should be implemented. Stage one would consist of an assessment, review, and approval of an application regarding the conceptual design and stage two would consist of the review and approval of the final engineering design of the new facility.

(f) The hearing date should be delayed in order to provide more time for preparation.

2.2 Other Participants' Views

The Alberta Trappers Association, the Official Opposition, the McMurray Independent Oil Workers and the Indian Association of Alberta all supported the Band's position. Suncor contended that, since it is neither applicant nor intervener, the information requested from it would be irrelevant to the Board's consideration of Syncrude's application.

3. Applicant's Views

Syncrude contended that:

(a) The Fort McKay location would mean additional costs, but if the Board found sufficient benefits, it would not object.

(b) The request for additional information should be denied because:

  (i) no distinction had been made between information required and relevant to the application, as compared to that required for an inquiry into the current operations. Syncrude argued that it is only the former that is relevant in the consideration of its application and any other information would not be relevant,

  (ii) the request is really for an inquiry into existing operations since all of the information requested relates to existing operations with the exception of the request for detailed information on the Sulfreen process,

  (iii) Syncrude cannot provide the requested information on the Sulfreen process because of contractual commitments to the manufacturer,

  (iv) supplying the additional environmental information would not answer the primary issues raised by the Band,

(v) denial of the request would not prejudice the Band's rights since it can always request the Board to convene an inquiry into current operations.

(c) A delay in the hearing date would adversely affect Alberta's public interest since it would have a serious impact on the timing of the development. Unless Syncrude has an approval by September 1, 1984 the development could be delayed by 4 to 6 months.

4. The Board's Views

The Board's views after careful consideration of the submissions are as follows:

(a) It sees no reason why the Band's intervention should not be heard at Fort McKay and therefore concurs with the request.

(b) With respect to the Band's request for additional detailed performance and design data relating to the proposed new emission control equipment, the Board believes that Syncrude has submitted sufficient documentary evidence to allow the matter to proceed to a hearing. Further detailed information may be elicited during cross-examination by participants.

(c) With respect to the Band's request for additional environmental monitoring information, the Board believes that:

(i) virtually all of the requested data relate to existing operations which are not relevant to a consideration of the current application.

(ii) Guide-23 does not apply to an amendment to an existing operation particularly where operations have been in effect over a long period of time and it is feasible to test, on the basis of actual experience, whether there are environmental impacts, and

(iii) the data requested would not appear to be of any assistance in answering questions of whether operation of the two plants is having an impact on the health of the residents of Fort McKay.

Therefore the Board is not prepared to ask Syncrude to provide the environmental monitoring data to the Band. However, the available monitoring information from Syncrude and Suncor may be obtained from Alberta Environment if such a request is made to that Department by the Band.

(d) With respect to the Environmental Law Centre opinion, the Board continues to question whether it has the jurisdiction to deal with general health issues other than where there are indicated impacts of energy operations.

(e) With respect to the proposed two-stage hearing process, the Board can see some advantages to it for new applications, where there is a need to deal with broad issues such as basic need and location. However, in the case of an amendment to an existing operation that has been in effect for many years, the Board does not believe there are net advantages.

(f) With respect to the proposed deferral of the hearing, the Board accepts the position of the Band that the time to file its intervention, by July 13, is not sufficient and that some additional time is required. It also agrees with Syncrude that delays could have a significant impact on the broad Alberta public interest. Since the Board has not agreed to the request for additional data, or to the implied proposal of the Band that existing operations be considered at the Syncrude hearing, the time required to file an intervention, or prepare for the hearing, has been considerably reduced over what was probably assumed at the June 15 meeting. The Board believes that deferral of the hearing date, from July 23 to August 20, would be reasonable, as would a deferral of the date for filing interventions from July 13 to August 10.

(g) With respect to the evidence to be presented at the hearing, the Board will require that the information relate to the specific application that was filed by Syncrude and not to the historical operations of the Syncrude and Suncor plants.

5 OTHER MATTERS

The foregoing discussion has dealt with the request for additional environmental information and related matters as they pertain to the current Syncrude application.

(a) At the pre-hearing meeting, Syncrude suggested that if there are general questions, such as health impacts, respecting the existing or historical operations of the Syncrude and Suncor plants, then the Band might request the Board to convene an inquiry for that purpose. In fact, Chief McDonald requested the Board to convene such an inquiry in a telex dated 15 May 1984. Reference was made, in the telex, to a 1982 study by National Health and Welfare and a current study being carried out by the Universities of British Columbia and Simon Fraser. In the latter case, reference was made to the study finding that hair tissue samples of six individuals had shown elevated lead levels. The Board responded by stating that it had not seen reports on either of the studies and would not be in a position to make a decision until it had that information.

(b) At the pre-hearing meeting, a copy of the proposal for the current study was filed by the Band. It provides not only details of the plan for the current study, but also a brief description and findings of the 1982 study. The Board notes that the report states that Dr. Eaton, of the Federal Department of Health and Welfare, conducted a medical study in the winter and spring of 1982, which included analyzing blood samples for lead. The report states that Dr. Eaton reported to Chief McDonald that "all results were... within normal ranges, with the exception of some individuals with low serum vitamin C levels, one boy with an elevated blood lead level and several individuals with elevated arsenic levels."

(c) With respect to the current study, the report states that the study is designed "to determine if exposure of the residents of Fort McKay to materials from stack emissions and effluent discharge from oil sands extraction plants can be ascertained." The report indicates that the means of making that ascertainment "is to compare levels of vanadium, nickle, aluminum, and molybdenum in scalp hair from the residents in Fort McKay with those in communities further removed from the extraction plants." The report states that the four metals were selected "as the most likely indicators of exposure to remain present in the body in an untransformed state." At the pre-hearing meeting, the Band reported that the current study had identified six people, two adults and four children, with elevated lead and cadmium levels. However, no information was provided as to whether or not the study found that Fort McKay residents differed from the other two communities with respect to vanadium, nickle, aluminum, and molybdenum - the metals that were selected to ascertain whether the "stack emissions and effluent discharge from the oil sands extraction plants" were having an impact. As the Board understands the study plan, unless the results show that Fort McKay residents have higher levels of the four marker metals than the other two communities, there is no basis for assuming that emissions from the oil sands plants are the cause of elevated levels of lead and cadmium in Fort McKay residents. Accordingly, the Board continues to be of the view that it cannot make a decision with respect to the need for an inquiry until it has had an opportunity to review the two reports.

6 DECISION

The Board agrees to hear the Band's intervention in Fort McKay, but it cannot support the Band's request for additional information from Syncrude on the proposed new emission control equipment, or for additional environmental monitoring data from Syncrude or Suncor. Also, the Board sees no net advantage in the two-stage hearing process for this application. In order to allow adequate time for participants to file interventions, the Board has deferred the hearing date from July 23, 1984 to August 20, 1984, and the date for filing interventions from July 13, 1984 to August 10, 1984. With respect to the health inquiry, the Board maintains that it cannot determine the necessity for one until it has had an opportunity to review the two reports.

ISSUED at Calgary, on 27 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Board Chairman

N. Strom, P.Eng.
Board Member

V. Bohme, P.Eng.
Board Member

APPENDIX 1

THOSE WHO APPEARED AT THE MEETING

PARTICIPANTS	REPRESENTATIVES
Syncrude Canada Ltd. (Syncrude)	A.L. McLarty
The Fort McKay Indian Band (Band)	Chief D. McDonald G. Bethell J. Brisebois
Suncor Inc. (Suncor)	K.S. MacFarlane
Alberta Trappers Association	J. Rogers
McMurray Independent Oil Workers	B. Ross
The Official Opposition	B. Redlin
Indian Association of Alberta	C. Freeman
Energy Resources Conservation Board staff	M. Bruni R.G. Evans, P.Eng. D. Bannister, P.Eng.

ERCB

Requirements for Major Electric Transmission Lines In the Edmonton Area

Inquiry

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ERCB

Requirements for Major Electric Transmission Lines In the Edmonton Area

Inquiry

February 1984

CONTENTS

Page

EXECUTIVE SUMMARY 1

1 INTRODUCTION 3

2 SCOPE OF INQUIRY 3

3 VIEWS OF PARTICIPANTS 3
- Electric Load Forecast 3
- Facilities 4
- Constraints 4
- Criteria 6
- Alignments 7
- Implementation 8

4 VIEWS OF THE BOARD 10
- Electric Load Forecast and Facilities 10
- Constraints 10
- Criteria 11
- Alignments 11
- Implementation 12

5 FINDINGS 12

FIGURES

1 ERCB — EDMONTON AREA — EXISTING MAJOR ELECTRIC TRANSMISSION LINES 15

2 EUPC — EDMONTON AREA MAJOR TRANSMISSION LINE CONSTRAINTS 17

3 E.M.R.P.C. CONSTRAINT FACTORS 19

APPENDIX

I THOSE WHO APPEARED AT THE HEARING 21

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BOARD INQUIRY INTO REQUIREMENTS FOR MAJOR ELECTRIC TRANSMISSION LINES IN THE EDMONTON AREA

Inquiry D 84-1
Proceeding 821051

EXECUTIVE SUMMARY

This inquiry was called to identify future major transmission lines needed to supply electric energy requirements in the Edmonton area, as well as to consider how those requirements might best be met having regard for the many physical constraints in the area.

Electric utilities, municipal planning bodies, the cities of Edmonton and St. Albert, Alberta Government Telephones, and Transport Canada participated in the inquiry.

There was a general concensus that

1. Long-term growth will require major (probably 500-kV) transmission lines from the Ellerslie substation to the south, and possibly to the east.
2. Long-term power plant developments may result in the need for major transmission facilities in the northwest, either south of Big Lake or east of St. Albert, but this requirement is less definite than that in the southeast.
3. The southern requirement traverses an area that is subject to active development (urban and industrial) and already has substantial constraints as indicated on the map attached. The number of constraints will increase with time and unless steps are taken now to plan for the transmission lines there are likely to be serious problems when that need finally develops.

Several planning alternatives were suggested. While the establishment of either a special or a multi-use corridor would provide a suitable solution, there was no indication that such a corridor was being seriously contemplated and the Board does not believe that it is a realistic possibility under current or foreseen circumstances. The Board believes that the most practical alternative would be to incorporate the right of way within the transportation plan that is expected to evolve for the area. It intends to have discussions with Alberta Transportation and others to explore this possibility.

CONCLUSIONS

To Utilities and Planners:

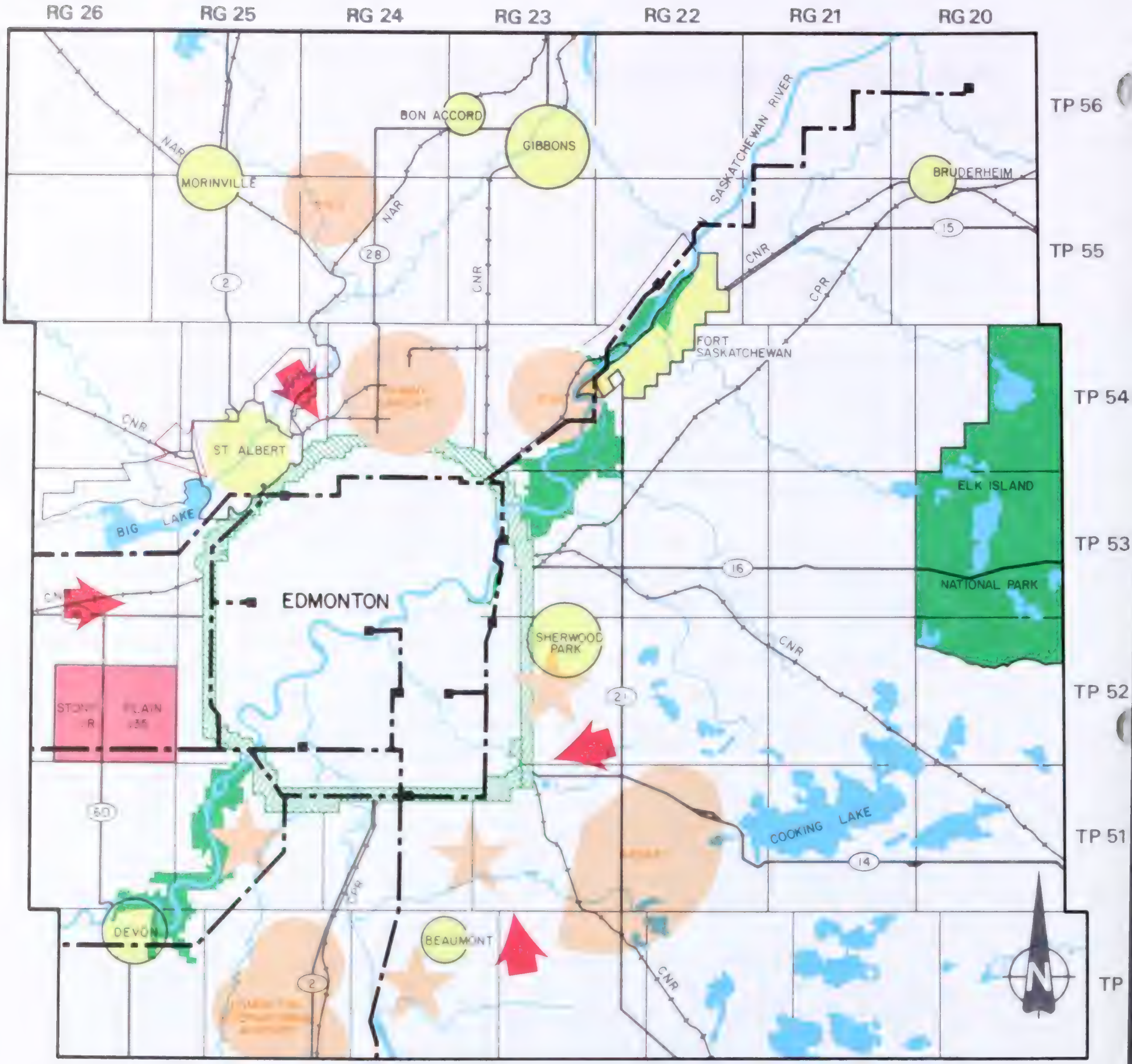
The Board believes that electric utilities and planning agencies should continue to discuss development plans for land use, and for future electric transmission lines around Edmonton, with a view to firming up transmission planning within a few years. Board staff are available to assist in this process.

To Planners:

Planning agencies appear to be in the best position to alert potential land developers to the need for future electric transmission lines in the geographical areas outlined in this report. The Board recommends that potential developers be alerted and, wherever possible, a suitable warning be added to area plans as they are developed and documented.

To Transportation Planners:

Should multi-purpose corridors be established in the northwest or southeast for other reasons and uses, particularly development of the transportation system, provision should be made for inclusion of transmission lines similar to the provisions for rights of way within the existing RDA.



LEGEND

- EXISTING 240kV AND 500kV TRANSMISSION LINES ‒ · ‒ · ‒
- EXISTING SUBSTATION SITES ■
- TRANSPORTATION & UTILITY CORRIDOR ▨
- RESTRICTED DEVELOPMENT AREA AND NATIONAL PARK 🟩
- MAJOR CONSTRAINT AREAS ●
- RADIO STATION CONSTRAINT ★
- POTENTIAL CORRIDOR ⬅

SOURCE EUPC (FEBRUARY 1983)

EDMONTON AREA
MAJOR TRANSMISSION LINE CONSTRAINTS

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BOARD INQUIRY INTO REQUIREMENTS FOR MAJOR ELECTRIC TRANSMISSION LINES IN THE EDMONTON AREA

Inquiry D 84-1
Proceeding 821051

1 INTRODUCTION

1.1 Background

At a public hearing held in Edmonton during December of 1980 to consider an application for 500-kV transmission lines from Keephills to Ellerslie, several interveners urged the Energy Resources Conservation Board to play a more active role in the planning area. Therefore, in its Decision Report 81-D respecting these 500-kV lines, the Board said it would consider convening a public inquiry to consider the long-term transmission line requirements for the Edmonton area. This was also in response to the Alberta Government's transmission line policy, which called for consideration of Alberta's long-term transmission line requirements with the objective of permitting and encouraging long-range planning and participation by all interested parties.

1.2 The Inquiry

The Board held a public pre-inquiry meeting on 19 November 1982 in Edmonton to hear comments and views regarding the inquiry. After considering these submissions, the Board issued a Memorandum of Decision outlining the procedures to be used and the scope of the inquiry.

The inquiry was held in Edmonton on the 5th and 6th of July 1983 with V. Millard, V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting. Those whose appeared at the inquiry are identified in Appendix I.

Before the filing of final submissions, staff of the Board's Hydro and Electric Department held an informal workshop meeting on 2 June 1983 at the Chateau Lacombe in Edmonton with those parties who filed initial submissions. The purpose of the workshop was to provide an opportunity for the inquiry participants to better understand the submissions. Each party briefly summarized its submission, areas where additional material was warranted were identified, and an informal discussion clarified the submissions.

2 SCOPE OF INQUIRY

The Memorandum of Decision from the pre-inquiry meeting established that the scope of the inquiry would include consideration of:

(a) the Edmonton area forecast electric load as part of the overall Alberta forecast;

(b) the major electric transmission lines and substations expected to be required to meet the future area load, and the sensitivity of the timing of such facilities to the forecast load;

(c) the identification of routing constraints, existing and planned developments (regional and municipal), highways, pipelines, corridors, and airports, etc;

(d) the criteria to be applied in evaluating and selecting transmission line routes and substation locations; and

(e) the requirements and alignments for future corridors.

3 VIEWS OF PARTICIPANTS

3.1 Electric Load Forecast

The Electric Utility Planning Council's (EUPC) report outlining planned and potential needs for transmission lines was based on its 1982 Energy and Demand Forecast. The EUPC stated that the forecast could vary by as much as 20 per cent by 1997 and not have any significant effect on transmission planning. It expected lower growth than that depicted in its 1982 forecast but said this would result in project deferment of four to five years and was not significant enough to change long-term transmission planning as most of the long-range transmission projects are primarily related to generation development.

All participants accepted the EUPC growth projections for the purposes of their submissions to the inquiry. The Edmonton Metropolitan Regional Planning Commission (EMRPC) noted that the EUPC forecast should be viewed as very long term, that variation in load requirements and timing of specific projects could be expected, and that potential transmission developments are far into the future, especially if the EUPC load forecast proves high.[1]

3.2 Facilities

The EUPC submitted a detailed plan for major substations and line additions with modifications in the short and long term under three possible generation development scenarios. It concluded that, for purposes of supplying load within the Edmonton area, the existing 240-kV ring (Figure 1) with the addition of some new circuits into the east and northeast of the city and the addition of some 240-kV distribution substations would be sufficien in the period studied. It noted that there will be a requirement for an additional 240-kV transmission line into the downtown area to meet the growing load.

The EUPC stated that the need for future access to the Edmonton area transmission hub will be primarily a result of the development of new generating sites. Development of transmission around the Edmonton area is much more sensitive to the timing and magnitude of new generation in Alberta than to load growth in the Edmonton area.

The City of Edmonton noted that the EUPC evaluation was consistent with Edmonton Power's long range conceptual electrical plan and that the only major transmission additions required within the city boundary in the next 20 years are the TransAlt Utilities Corporation (TransAlta) 240-kV circuit from Ellerslie to the Fort Saskatchewan area, on the east side of the city, and the 240-kV supply from th west end to a new downtown station. The City o Edmonton stated that the inner city 72-kV suppl system cannot be economically expanded and most new substations will connect to the city's 240-kV ring.

As long-term requirements indicated very little transmission line development within the city, interest centred on corridors and long-range land-use planning issues involved in transferring electric energy to, and around, the Edmonton area from remote generating stations.

3.3 Constraints

The EUPC stated that the Edmonton area is already severely constrained so work should proceed promptly in delineating corridors. In order to identify potential transmission corridors, the EUPC evaluated the general location and approximate area of major constraints to future transmission line developments. These contraints together with the EUPC's potential transmission corridor alignments are depicted in its map entitled Edmonton Area Major Transmission Line Constraints (Figure 2). This map identifies some of the most obvious constraints that cause concern in the northwest and southeast areas where 240- and 500-kV corridors would increase with time. The EUPC stated that failure to consider the potential development of future transmission lines in these areas would make it very difficult and expensive to gain public acceptance and construct facilities when needed. It recommended that a mechanism be developed to ensure that land-use planning for the Edmonton area includes provision for rights of way for future transmission line requirements and, particularly in the northwest and southeast, should recognize and reserve access for future transmission lines to ensure that the optimum facilities will be possible with minimum impact on land use or the public.

The EMRPC used its list of land-use planning principles to access several key constraints to transmission line development and several other constraints which allowed some flexibility, through the use of appropriate mitigative techniques, in delineating potential penetrator corridors. The EMRPC assessed existing and proposed land-use areas, infrastructure locations, environmentally sensitive areas, and other linear developments. EMRPC constraint factors and potential corridor locations are shown on its map entitled E.M.R.P.C. Constraint Factors (Figure 3).

The EMRPC proposed the following as major constraints to corridor development:

- existing residential areas;
- close proximity to farm houses, rural residences, and places of business;
- existing and planned transportation and communication systems that could be compromised;
- routes other than along section lines, quarter section lines, or property lines to minimize interference with agricultural practices;
- areas with adopted area structure plans;
- future urban expansion areas that might be fragmented;

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[1] Since the inquiry, the EUPC has published its 1983 forecast which confirms expectations that the load will be significantly less than predicted in the 1982 forecast, and that potential transmission developments will likely be deferred.

- facilities such as defense installations, fixed commercial communication systems, and established air space and navigation aids; and
- resource-extraction projects.

From a regional land-use perspective, several recurring areas of concern were identified by the EMRPC:

- existing concentrations of residential and industrial nodes offer varying degrees of compatibility with linear developments - country residential nodes and heavy industrial nodes in the County of Strathcona should be avoided;
- south and east of Big Lake, recognized sensitive land-use areas should be avoided; and
- all of the potential corridors indentified by the EUPC and EMRPC impact in varying degrees on the various communication interference zones and airport control facilities identified around the Edmonton area.

The EMRPC concluded:

- that the development of any linear facility required in or near the Edmonton area is already constrained by urban development and other land-use commitments;
- there is a real concern that failure to secure suitable corridor locations at this time will limit the choices available in future, and that land-use impacts and environmental and socio-economic considerations will be harder to address in the future;
- there is a need for penetrator corridors in the Edmonton area; and
- the continued proliferation of single-facility rights of way increases land fragmentation, intrusion in urban areas, and potential conflict with adjoining land uses.

The City of Edmonton stated that a decision with regard to the identification of penetrator routes into the city must be made in the near future as transmission line options will be progressively reduced. The City of Edmonton noted that it was imperative that the most suitable penetrator routes be identified and specific implementation mechanisms be formulated and exercised at the earliest possible time.

The City of Edmonton noted that from a land-use planning perspective and in respect of the EUPC potential transmission corridors:

- there do not presently appear to be major constraints resulting from proposed or committed land uses in the southeastern section of the city;
- the corridor tentatively proposed for the areas east of Beaumont might be best accommodated by a southerly extension of the existing Sherwood Park Restricted Development Area (RDA) and this would not impact land uses in the city;
- the potential alignment approaching the city directly from the west may encounter constraints in the Lewis Farms and Winterburn areas; and
- land-use planning constraints do not appear to be significant at this time in the general locations of the remaining two potential penetrator corridors in the northwestern sector.

The City of St. Albert's observations regarding EUPC potential corridors were:

- the potential corridor located immediately east of Big Lake would place serious constraints on the planned development of major industrial, recreational, and environmental land uses within the city and would be opposed by St. Albert;
- the potential corridor south of Big Lake, parallel to Highway 16, is supported by St. Albert; and
- the potential corridor to the east of St. Albert creates possible constraints to the development of future industrial lands but does not restrict St. Albert land-use development as significantly as that located immediately east of Big Lake.

TransAlta noted that there are some problems with co-ordination among various uses in a multi-use corridor and suggested that, while multi-use corridors have some advantages, single-use corridors should also be considered.

Stewart, Weir & Co. stated that the opportunity now exists to co-ordinate land-use planning and linear facility development to reflect the legitimate access requirements of industry while recognizing the options to eliminate or reduce the external effects of such facilities on urban land uses. Building upon the information submitted by the EUPC, this participant addressed the use of multi-use corridors as an appropriate planning mechanism in the Edmonton area. In this context, constraints outlined by Stewart, Weir & Co. were:

Land-Use Constraints

- where possible, corridor alignments should follow existing rights of way;
- where possible, corridor alignments should be in industrial areas, or areas of land-use or planning-unit interface;

- alignments should lie adjacent to quarter sections and parcel or field boundaries;
- alignments should not bisect existing or committed planning units;
- corridors for hazardous product pipelines should not bisect or lie directly adjacent to residential, institutional, or other population concentrations;
- alignments should avoid existing and proposed parks;
- alignments should avoid proximity to rural farmsteads or country residential areas; and
- corridor alignments should avoid federal lands and Indian reserves.

Environmental Constraints

- alignments must allow for topography and landscape features;
- the number of water or drainage-course crossings must be minimal and those chosen should reflect a balance of the optimal geophysical site and the minimal environmental impact;
- alignments should avoid areas of critical aquatic and terrestrial habitat;
- alignments should avoid significant historical or cultural resources and ecological or natural areas;
- alignments should avoid unstable slopes and organic soils;
- alignments should preserve windrows and protective vegetation in agricultural areas; and
- alignments should avoid mineral resource extraction areas.

Technical Constraints

- corridors for electric transmission lines should not interfere with communication, radio, railroad, and air-traffic control communication systems, preferably by avoiding these facilities or, where not avoidable, by the use of mitigative devices;
- corridor alignments should minimize the crossing of existing linear facilities;
- corridor alignments will tend to follow the least flexible component but should recognize the requirements of the more flexible components;
- the extra cost of using corridors could be reduced by corridor alignments being located where right of way needs have been identified and by shortened route lengths and reduced deflections; and
- corridor alignments should not significantly reduce the reliability of the component facilities.

Transport Canada's submission outlined areas of concern relating to the proximity of transmission lines and substations to its non-directional beacons, instrument landing systems, radar, and runways. It confirmed that the safe distances specified in its submission were not absolutes but identified areas where Transport Canada would like to be advised of planned electrical facilities. A detailed evaluation on a case by case basis would permit Transport Canada to give a precise set-back distance from airport facilities and to discuss mitigative measures as warranted.

Alberta Government Telephones (AGT) stated that it would like to participate in the process of establishing transmission line routes to minimize possible interference with AGT communication facilities.

3.4 Criteria

All the participants recognized that the selection process for transmission line routes and substation locations must be based upon a wide range of technical, environmental, and land-use concerns. The EMRPC recommended, as general land-use planning principles, that proponents of transmission line rights of way and multi-use corridors consider the following issues:

Land-Use Issues

- Route lines so as to locate them in or be parallel to established utility or energy corridors.
- Maximize the opportunities to locate in multi-use corridors.
- Avoid the fragmentation of future urban expansion areas.
- Provide mechanisms for public input during the corridor/route selection process.
- Avoid penetrating existing developed areas.
- Avoid diagonal routes because of increased land-use impacts.
- Minimize the physical and visual impact on people.
- Route transmission lines/corridors through industrial areas rather than residential areas.
- Route lines adjacent to areas planned for land-use changes rather than divide planning areas (eg residential to industrial).
- Avoid approved and anticipated Area Structure Plan areas.

Rural Issues

- Minimize effects on prime farmland.
- Route along section lines, quarter section lines, or property lines to minimize interference with agricultural practices.
- Route on range or uncultivated land rather than cropland to minimize economic and other impacts on agricultural practices.
- Avoid close proximity to farmhouses, country residential development, and places of business.

Environmental Issues

- Avoid designated or registered recreational, historic, archeological, or other culturally significant areas.
- Minimize disturbance of shelterbelts, woodlands, and wooded areas.
- Avoid disturbance of unique or rare species of plants and animals.
- Avoid interference with designated or registered areas of conservation or ecological importance.
- Minimize interference with existing surface water drainage patterns.
- Avoid physical features that result in excessive span lengths.
- Avoid areas of unstable soil.
- Select alignments that respect the topography and the aesthetics of the landscape.

Technical Issues

- Avoid interference with facilities such as defence and commercial navigational installations and fixed commercial communication systems.
- Avoid interference with established airspace.
- Avoid interference with public facilities such as reservoirs and municipal water sources.
- Minimize interference with extraction of mineral resources.
- Minimize total line length to reduce overall impact and cost.
- Maximize use of existing rights of way.
- Ensure the reliability and security of the Alberta electric system and the compatibility of short-term projects with long-range provincial plans.

The City of Edmonton concurred with the EMRPC's assessment criteria, recognizing that the overall ranking of the relative significance of each factor is site specific. Edmonton Power stated that its most important consideration is economics and that in many cases it is a trade-off between cost and satisfying land-use and environmental concerns.

Stewart, Weir & Co. also agreed with the EMRPC's criteria, however, it stressed that the multi-use corridor concept should be first and foremost in situations involving multiple linear rights of way in areas with severe constraints to linear facilities.

TransAlta also concurred with EMRPC's criteria list provided that electrical and cost considerations received equivalent recognition.

The City of St. Albert presented some guidelines that generally concur with the EMRPC's criteria.

3.5 Alignments

The EUPC view of available corridors for new transmission lines is depicted in Figure 2. The EUPC noted that, while it appears likely that facilities would be required in these areas and that land for corridors is currently available, there is no guarantee that transmission lines will ever occupy any of the corridors. Recognizing the future electrical requirements in the Edmonton area and the existing constraints, rights of way in the form of penetrator corridors should be investigated in the northwest and southeast, but primarily the southeast. Even where corridors are established, however, there should be no dictate that all transmission lines must use a particular corridor as there may be circumstances that would necessitate them being outside the corridor. The EUPC noted that while a corridor in the northwest and southeast should be considered, the northwest penetrator could be eliminated by taking power from Dunvegan, Judy Creek, and/or Slave River directly to Deerland east of Edmonton. The EUPC stated that a decision on the Slave River project will be made in the next year or so, and believed that that might be a more appropriate time to consider actual corridor alignments. A decision on the project would help to fix long-term transmission line requirements in the Edmonton area.

The EMRPC identified possible corridors where linear developments could by-pass areas of high constraint to connect to the RDA. Three of the corridors identified by the EMRPC are identical to those shown in the EUPC report. These corridors are shown on Figure 3 of this report.

The EMRPC acknowledged the northwest and southeast penetrator corridors and agreed that there might be a need to reserve land. The EMRPC suggested that municipal planning authorities should give consideration to the routing concerns identified in the northwest and southeast Edmonton areas. The selection process employed by the EMRPC and the EUPC had identified eight potential corridor locations which provide a conceptual basis for further screening and evaluation. While it recognized EUPC concerns in the northwest and southeast areas, the EMRPC stated that the uncertainty of transmission line development together with the opportunities available for joint-facility use of penetrator corridors necessitated a comprehensive review of all corridor opportunities. The EMRPC believed that a transmission corridor need has not been clearly demonstrated at this time in the southeast or northwest and that a corridor should not be established until need is demonstrated. While it did not favour sterilizing land, the EMRPC believed that committing land for multi-use corridors may be appropriate because of the long-term requirements of various linear developments.

Stewart, Weir & Co. presented five opportunity areas suitable for multi-use corridors containing transmission lines. It suggested that these areas required further study by government, regional, and municipal authorities and the general public. Specifically, it recommended that immediate consideration be given to the evaluation and establishment of at least two penetrator corridors — in the northwest and especially in the southeast.

The City of Edmonton stated that a decision regarding corridor alignments and related parameters must be made in the near future and affirmed that the northwest and southeast are appropriate locations for penetrator corridors. The City of Edmonton stated that, if penetration were to be in the northwest, existing corridors should be used to their maximum potential, possibly through replacing existing lower-voltage lines. If penetration occurred in the southeast, the City of Edmonton believed the RDA, with a possible expansion, would be most appropriate.

TransAlta concurred with the need to evaluate northwest and southeast penetrator corridors and specifically noted that the southeast is of primary concern because the Ellerslie substation is a key component in the provincial electric system and because of the existing contraints in this area.

3.6 Implementation

While implementation mechanisms for ensuring the preservation of rights of way were not specifically included in the inquiry terms of reference, implementation was addressed by a number of participants and emerged as a key element.

The EUPC recommended that a mechanism be developed to ensure that land-use planning included provisions for the rights of way of future transmission lines. While it stressed that work should proceed promptly in delineating corridors, it believed that setting aside land for multi-use corridors is preferable to setting aside penetrators simply for transmission line use. The EUPC concluded that the on-going planning process in Alberta is working reasonably effectively at the present time and can continue to develop and improve and that plans for future transmission facilities can be initiated without legislative initiatives or other directions.

The EMRPC expressed a number of views it believed should be considered in planning and implementing penetrator corridors:

- single-facility right of way development in the Edmonton Metropolitan area should not be supported or encouraged in the ERCB application process;
- consolidation and joint-facility development for various linear facilities should be actively promoted;
- the ERCB sponsor a study on corridor implementation options and invite industry, government, and related agency participation. Options considered might include:
    - advance purchase by electric utilities of required rights of way,
    - extension of the existing RDAs to include penetrator corridors,
    - provincial legislation to create special planning areas,
    - municipal or regional options to create special planning designations and protection measures through various statutory plan provisions;
- electric utility companies through the EUPC should undertake a more detailed examination of their corridor requirements in the Edmonton area, considering the material presented and issues raised at the inquiry;
- the EUPC should consider preparing a comprehensive plan for future long-term facilities in consultation with affected municipalities;
- the potential exists for improving the level of consultation and communication between planning agencies, ERCB, and EUPC through the subdivision and municipal plan referral process; and
- planning authorities should investigate how future facility development could be better addressed in their statutory plans.

While the EMRPC did not specify implementation options, it stated that existing planning tools and mechanisms available today cannot assure that land needed for future corridors will be reserved unencumbered or will be available for that use when it is required.

Stewart, Weir & Co. undertook a detailed examination of implementation options for the EMRPC and concluded that a planning approach that co-ordinates linear and land-use development is required because access options are rapidly being reduced. Options discussed were:

- **Status quo** — right of way acquired at the permit application stage. This option does not address long-term future right of way requirements, nor does it resolve land-use planning issues.
- **Company option** — where the company identifies and acquires future access routes at its own discretion. However, without an approved permit to construct, the company cannot acquire the right of way from landowners not willing to participate voluntarily in long-term easement options. Moreover, unless the companies place their alignments adjacent to existing or proposed rights of way, land-use planning concerns would not be reduced.
- **Utility Corridor Act** — creation of a corridor authority with the mandate to establish and manage corridors. The corridor authority could be a new governmental agency, an existing government department or agency, or a formal inter-agency committee. The authority must have the power and funds to fully implement the corridor concept. This option would infringe upon the jurisdiction of existing agencies, which implies that either the new Act must have a superior standing over existing Acts and regulations, or the Act must provide a mechanism for negotiation between overlapping jurisdictions. Further, this Act should make provision for substantial public input, ideally through direct representation at the decision making level.
- **Special Planning Areas (SPA)** — the Alberta Government, via section 144 of The Planning Act, 1977 has the authority to establish an SPA. Since corridors can be viewed as single-use areas, the SPA designation may be inappropriate. In addition, both pipelines and powerlines are exempt from the Planning Act.
- **Restricted Development Areas (RDA)** — the RDA regulations are similar to those for the SPA, but explicitly state that those areas can be for the purpose of establishing corridors. The RDA regulations have superior standing over all other Acts and regulations, thus granting the administrators extensive control over the development of these areas. Furthermore, since proposed penetrators would be designed to provide access into the existing Edmonton Transportation and Utility Corridor, their designations as an RDA would allow for the uniform administration of all corridors by the Department of the Environment
- **Highway Right of Way** — Cabinet could, through directive, require the Department of Transportation to acquire lands, for utility purposes, in excess of those needed for roads. However, this option presents a number of difficulties:
  - this option is only viable where a new road right of way is planned or an existing road is to be upgraded;
  - Department policy does not support the placement of parallelling facilities within the highway right of way;
  - the Minister of Transportation does not have the authority to create regulations that would control the development of the corridor lands by both the primary, secondary, and interim uses; and
  - the Department could face litigation challenging this option as being ultra vires.
- **Statutory Plans** — the Alberta Government would have to amend the Planning Act to explicitly allow for the designation of corridors in Regional Plans and Land Use Bylaws. A schedule of permitted uses and conditionally permitted uses could then be developed However, three major concerns appear to exist with the use of this option:
  - as both pipelines and transmission lines are exempt from **The Planning Act, 1977,** the planning agencies' involvement in corridors may be challenged in the courts;
  - the planning legislation does not allow for the confiscation of land for quasi-public use. Not only would the Act have to be amended to allow for the designation of corridors for potential future utility use but compensation would have to be made available to the landowners affected: and
  - as the planning authorities do not have lead agency roles in the ERCB permit process, key actors, ie the ERCB, Alberta Environment, and Energy and Natural Resources, must formally agree to support the use of the corridors

Stewart, Weir & Co. concluded that the non-corridor options present many difficulties and do not appear to support a comprehensive planning solution to the land-use issues. It stated that corridor preservation options all require modifications to existing legislation and active provincial government participation and may involve the massive expenditure of public funds. Although an approach requiring the Alberta Government to enact corridor legislation and establish a corridor authority may be the most difficult to pursue, it seems to be the most comprehensive corridor implementation and management mechanism. A second choice to the Corridor Authority would be the RDA with some legislative changes to allow proactive multi-use corridor planning.

Stewart, Weir & Co. asserted that input from the public, government agencies, and industry is required to determine if multi-use corridors are appropriate and, if so, to determine the exact number of penetrators, their appropriate widths and alignments, and the implementation procedure.

The City of Edmonton noted that while it did not have a solution to implementation of penetrator corridors it recognized the importance of early establishment of these corridors. It stated that an implementation mechanism available for use immediately following identification of penetrator routes is essential. The City of Edmonton asserted that present planning legislation could not preserve lands required for proposed electric transmission lines.

Corridor implementation options discussed by the City of Edmonton were:

- the utility companies obtaining easements from the respective surface rights owners;
- the utility companies obtaining the surface rights through the purchase of land — this action could be pursued by an individual utility purchasing its required right of way or a number of utility companies proceeding jointly as a consortium;
- provincial designation and ownership of rights of way in the form of transportation/utility corridors such as an RDA;
- provincial purchase of rights of way with sell-back provisions to the respective utility companies as transmission facilities are constructed; and
- city purchase of land required to accommodate a corridor.

TransAlta stated that it supported the EUPC view that a mechanism is necessary to ensure that land-use planning considers the need for future transmission lines. While it stated that it was uncertain how to preserve access, it preferred that the ERCB evaluate all the factors rather than having a split regulatory process as suggested in the establishment of a Corridor Authority. At the very least, TransAlta believed there was some merit in providing notification to all potential users of the need for future access routes as part of the planning process.

4 VIEWS OF THE BOARD

4.1 Electric Load Forecast and Facilities

The Board accepts that the forecast of expected load and the facilities to meet that load are essentially long-term projections and that variation of the actual load experienced from that projected may lead to variations in the installation dates of facilities of plus or minus five years or more. However, such variations do not significantly alter long-term needs. For the inquiry, the participants used the EUPC's 1982 forecast of electric load even though the EUPC itself characterized this forecast as being higher than the growth in electric load it now expected. The Board is of the view that in most cases variations in the electric load forecast would result primarily in a shifting of the installation dates of facilities without causing any substantial change in the type of facility or its eventual location.

At the time of the inquiry, a firm forecast of future electric generation requirements, location, and timing had not been developed much beyond approved power plants. Variations in the development of the generating pattern in Alberta might affect long-term transmission requirements in the Edmonton area. The Board is of the opinion that by the mid to late 1980s, the long-term generating pattern for the province might be better defined and the long-term transmission needs would also be more definite.

With these stated qualifications in mind, the Board is of the view that the most likely major additions within the city of Edmonton in the next 20 years are additional 240-kV substations near existing lines, 240-kV and 500-kV connections from the Ellerslie to the Fort Saskatchewan area, and a 240-kV supply to a new downtown substation from the west end of Edmonton. Some additional generation-related transmission is expected to develop around the south and eastern areas of Edmonton.

4.2 Constraints

The maps supplied by the participants pinpoint constraints very effectively and the Board sees no reason to comment in detail. The constraint-free areas indicate potential routes for future transmission line corridors.

Specific areas identified as being more attractive for a corridor location are:

- in the southeast part of the city of Edmonton;
- an area east of Beaumont and directly south of the existing east part of the RDA;
- one area for a northwest penetrator near St. Albert; and
- a possible corridor south of Big Lake and parallel to Highway 16.

4.3 Criteria

The constraints referred to in section 4.2, and the discussion of constraints provided by the participants at the inquiry, lead to a number of criteria that may be applied to the location of single transmission lines or transmission line corridors. Some criteria that follow directly from the constraints obviously require that certain developments be avoided but the vast majority of the constraints lead to the type of criteria that specify that an area should be avoided if at all possible.

The Board agrees that proper planning criteria for a corridor should be developed with regard to such factors as general economic, technical, and other concerns. However, when actual facilities are planned, the constraints and requirements specific to the facility need to be balanced with any general criteria set out for a corridor planning-based evaluation.

The Board is in general agreement with the proposition of Stewart, Weir & Co. that multi-use corridors are appropriate in situations where multiple linear rights of way are definitely needed and there are severe constraints to the development and location of linear facilities. The Board notes that Edmonton Power expressed a preference for single rights of way and that TransAlta expressed the view that major facility additions should not be withheld simply because single-line facilities were proposed in a particular instance. Obviously, it is easier to locate multi-use corridors early and prior to area plans and development. Such corridors could be located using the criteria discussed earlier in the report and general planning principles, but in the present situation it may not be feasible to establish multi-use corridors now.

The Board observes that a number of criteria that fall in the "avoid wherever possible" class apply to either single-facility transmission lines or to the establishment of corridors, and include but are not limited to:

- established community, residential, and industrial land use;
- areas of electronic interference with other facilities;
- federal lands;
- prime and scenic timber areas;
- prime agricultural areas;
- gravel deposits;
- established future recreational areas;
- streams;
- steep slopes;
- established or committed parks.

Wherever possible, given all the other criteria that must be applied, transmission lines should follow the shortest routes, the straightest routes, and existing access.

4.4 Alignments

As illustrated in the maps, a number of penetrator corridor locations were identified at the inquiry. Location of corridors in the areas suggested was based mainly on the constraints and the availability of land, except in the southeast where the need for a specific (probably 500-kV) transmission line was foreseen.

The evidence and views of most of the participants seemed to highlight two geographic areas where future routes and dedicated corridors would be required. In the Board's view, the most likely location for a route or routes is from the area of the Ellerslie substation east to about where the RDA turns north on the eastern side of Edmonton, with the routes running either east or south. An extension of the RDA south that would avoid the major constraint areas and pass to the east of the Town of Beaumont appeared to be a possible alignment.

The only other potential need that was identified was in the northwest, and even then there was some doubt as to whether this would be needed if transmission by-passed the city and interconnections were made at Deerland substation. The least contentious of the routes proposed appeared to be an alignment south of Big Lake and probably south of Highway 16. An alternative to this would be a penetrator route to the east of St. Albert, although the constraints appeared more significant in this area.

Having recognized two areas where routes are expected to be needed in the future, the Board then considered the question of establishing a multi-facility or perhaps even a multi-use corridor. It appears to the Board that at this time it is not possible to specify in any detail the electric transmission requirements in even the most likely area, that is the area to the southeast. However, this does not prevent identifying a general alignment which could be used for either one or two transmission lines, for multiple facilities, or even for a multi-use corridor. The Board is of the opinion that such alignments should be identified in the southeast and in the northwest.

Should the need to set aside land for uses other than transmission lines cause penetrator corridors to be established in the southeast and northwest within the next few years, then the Board would recommend that provision be made for inclusion of transmission lines in such corridors.

Until such time as a multi-facility corridor is established, the Board sees no reason why single transmission line alignments should not be considered provided that the constraints identified at the inquiry are considered in establishing the alignment.

4.5 Implementation

Participants at the inquiry identified a number of possible methods of establishing routes or corridors by setting aside land prior to specific needs being established. The Board believes that the spectrum of possibilities is covered by the following examples:

- Taking no action at all until a specific proposal has been prepared and an alignment clearly identified.
- Establish some feature of the planning process which would provide a warning to planners and developers of a future need for a specific alignment.
- Alternatively, provide some feature of the planning process which would establish the future zoning and use of land along a particular alignment.
- A utility that expected at some time in the future to use a particular alignment for transmission lines would buy the land or obtain easement ahead of the actual need.
- The various municipalities involved could protect certain alignments through their approval process for developments.
- Land for the alignment of transmission lines could be acquired along with the acquisition of land for future transportation systems.
- The provincial government could pass legislation to create a special planning area and perhaps a special corridor authority, either or both of which would establish alignment for future transmission lines.
- There could be an extension of the existing RDA in the form of penetrator corridors as required.
- The provincial government could purchase rights of way for future transmission lines with sell-back provisions whereby the utilities would compensate the government for the cost of holding the land until needed.

Although the Board does not believe that the exact alignment of a future transmission line corridor can be established in either the southeast or northwest area at this time, it does believe that an alignment will be needed and should be brought to the attention of planners and developers and the public now. For this reason, the Board believes that area plans being developed should include a description of the probable alignment and future need for such transmission line corridors in the southeast and northwest areas.

Any such alignment must recognize the criteria and constraints identified at the inquiry and discussed in this report. The Board presents its interpretation of the result in the map entitled Future Areas For Transmission Line Corridors.

5 FINDINGS

Neither the precise need for, nor the exact location of, future electric transmission lines can be identified at this time. However, within two to five years the need should be more definite.

There is a probable need for future transmission lines in the northwest area and an almost certain need for future transmission lines in the southeast. For the southeast area, penetrator corridors will likely be needed both east and south from the present southeast corner of the RDA.

Notwithstanding that corridors for transmission lines will almost certainly be needed in the southeast, and probably in the northwest, multi-purpose corridors cannot be justified at this time on the basis of future electric transmission lines alone.

Should multi-purpose corridors be established in the northwest or southeast for other reasons and uses, particularly development of the transportation system, provision should be made for inclusion of transmission lines similar to the provisions for rights of way within the existing RDA.

Those planning other land uses in the northwest or southeast areas should be made aware of the expected need for future transmission lines in the vicinity.

Planning agencies appear to be in the best position to alert potential land developers to the need for future electric transmission lines in the geographical areas outlined in this report. The Board recommends that potential developers be alerted and, wherever possible, a suitable warning be added to area plans as they are developed and documented.

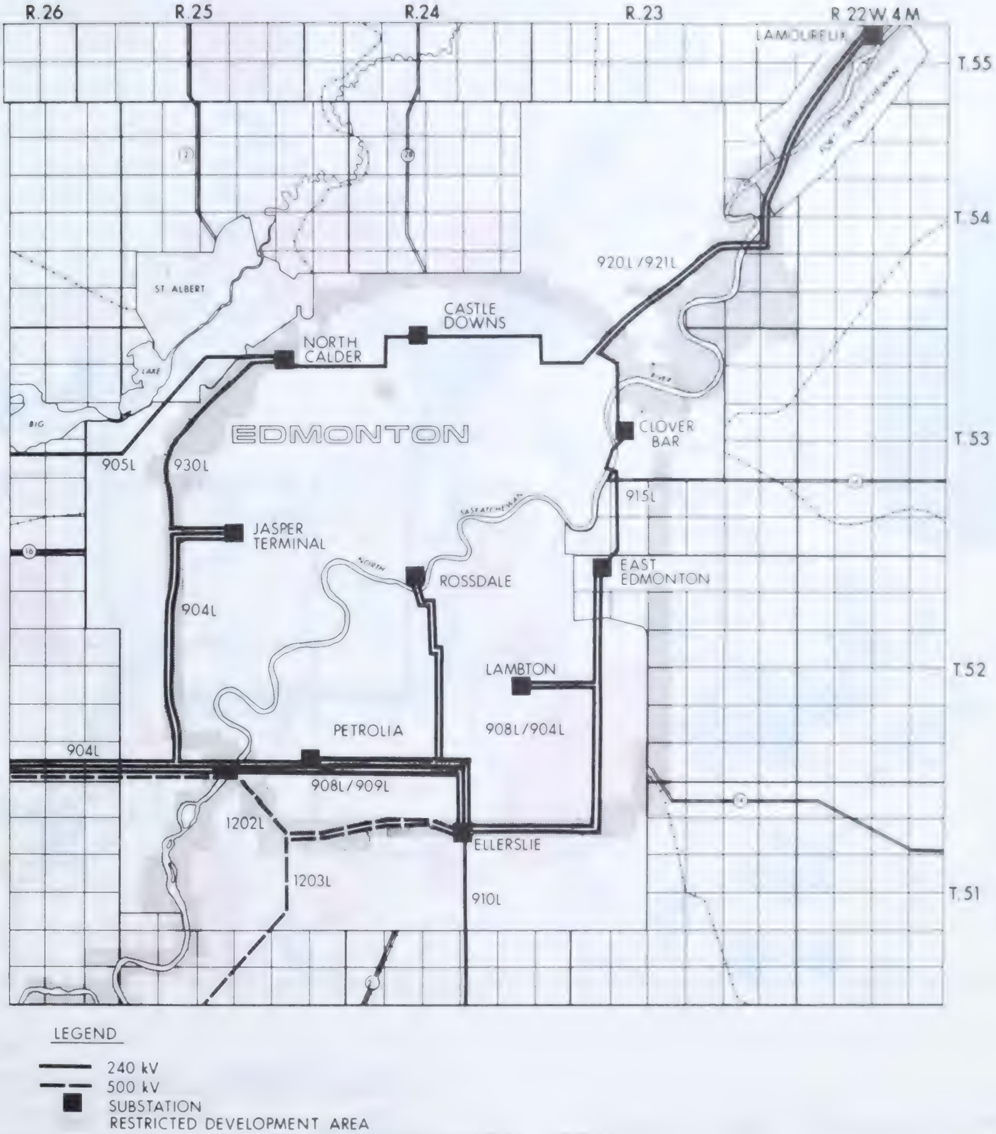
The Board concludes that electric utilities and planning agencies should continue to discuss development plans for land use and for future electric transmission lines around Edmonton with a view to firming up transmission planning within a few years. Board staff are available to assist in this process.

DATED at Calgary, Alberta on 22 February 1984

V. Millard
Chairman
Millard

V. E. Bohme
Board Member
V. E. Bohme

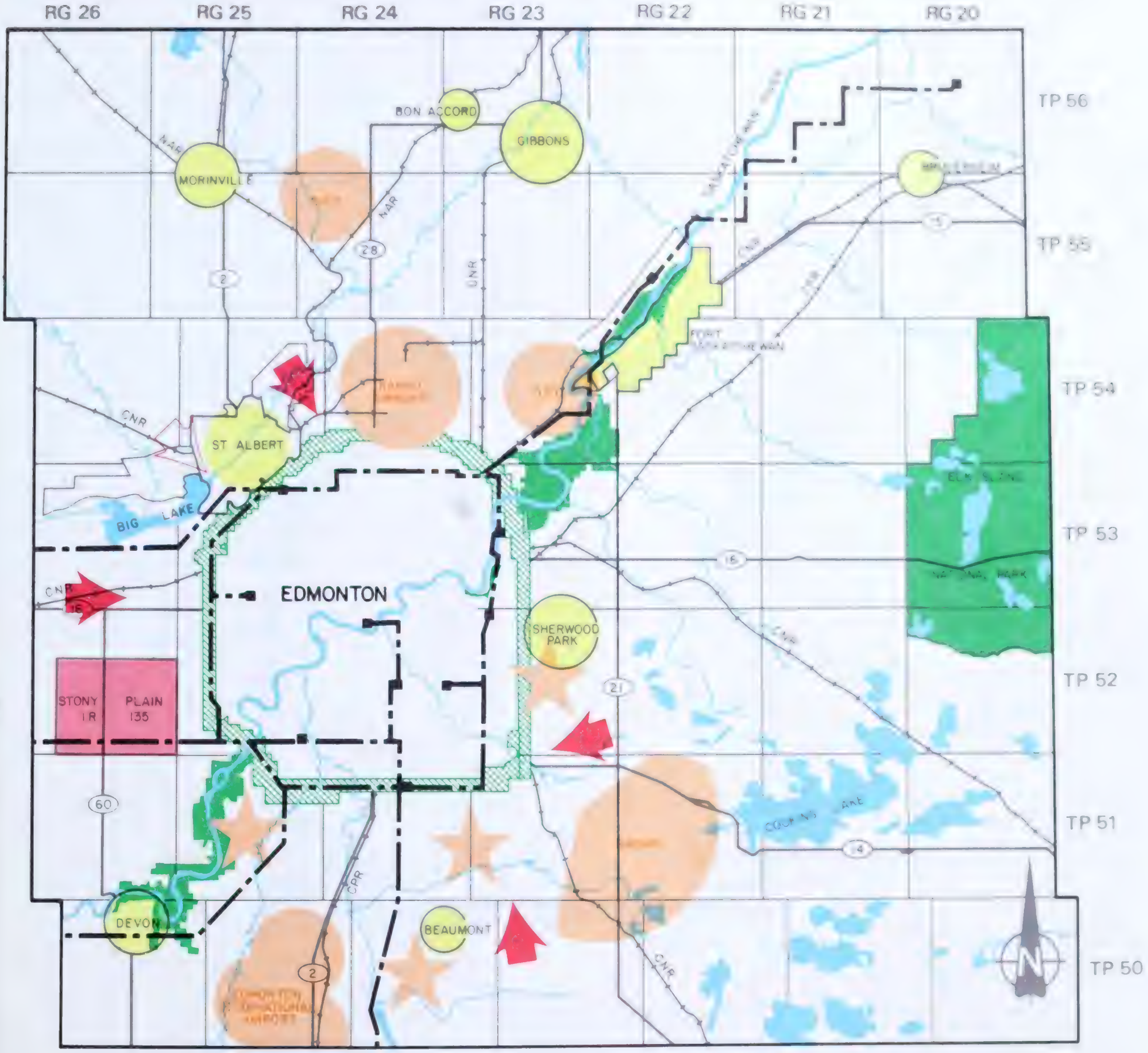
C. J. Goodman
Board Member
C. J. Goodman



EDMONTON AREA

MAJOR ELECTRIC TRANSMISSION LINES

FIGURE 1



LEGEND

- EXISTING 240kV AND 500kV TRANSMISSION LINES
- EXISTING SUBSTATION SITES ■
- TRANSPORTATION & UTILITY CORRIDOR ▨
- RESTRICTED DEVELOPMENT AREA AND NATIONAL PARK 🟩
- MAJOR CONSTRAINT AREAS ●
- RADIO STATION CONSTRAINT ★
- POTENTIAL CORRIDOR ◀

SOURCE EUPC (FEBRUARY 1983)

EDMONTON AREA
MAJOR TRANSMISSION LINE CONSTRAINTS

FIGURE 2

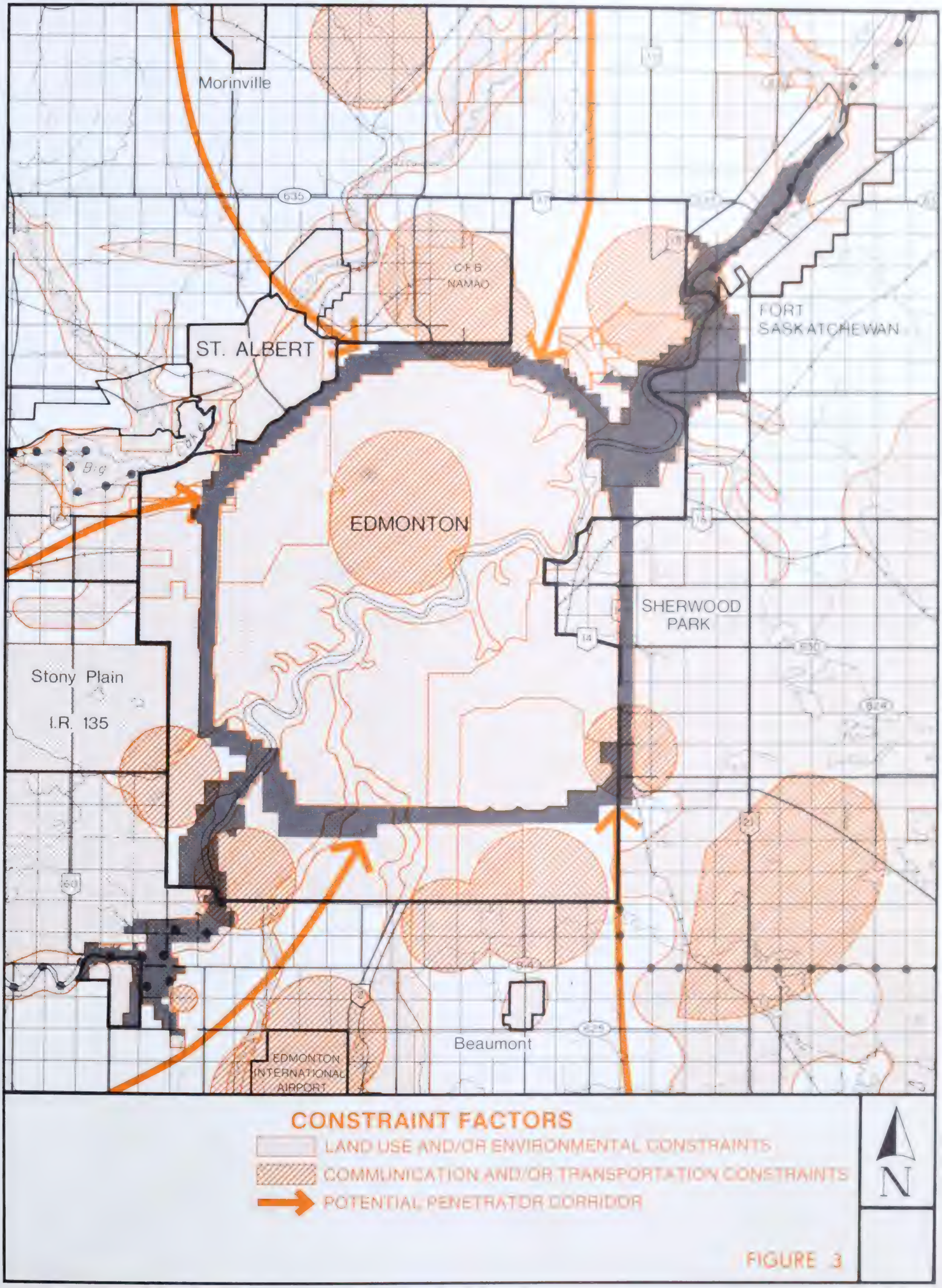

Morinville
635
37
CFB NAMAO
ST. ALBERT
FORT SASKATCHEWAN
Big Lake
EDMONTON
16
SHERWOOD PARK
14
630
824
Stony Plain
I.R. 135
21
60
814
2
625
Beaumont
EDMONTON INTERNATIONAL AIRPORT
CONSTRAINT FACTORS
LAND USE AND/OR ENVIRONMENTAL CONSTRAINTS
COMMUNICATION AND/OR TRANSPORTATION CONSTRAINTS
POTENTIAL PENETRATOR CORRIDOR
N

FIGURE 3

SOURCE: EMRPC (MAY 1983)

APPENDIX I

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	**Witnesses**
Electric Utility Planning Council (EUPC) E. O. McAvity	P. Roxburgh, P.Eng. J. Beckett, P.Eng.
Edmonton Metropolitan Regional Planning Commission (EMRPC) B. Fricson	R. N. Giffen, MCIP C. H. Weir B. Fricson
Stewart, Weir & Co. C. H. Weir	C. H. Weir J. Sherritt J. Racy
Transport Canada H. G. Gawne	H. G. Gawne E. Magurole
City of Edmonton M. Sherk	A. Sadesky, P.Eng. F. Kardel, P.Eng. L. Dale
City of St. Albert S. Weary	S. Weary
TransAlta Utilities Corporation (TransAlta) H. D. Williamson	M. D. Rogers, P.Eng. W. A. Hosie, P.Eng.
Alberta Government Telephones (AGT) H. Koumarelas	H. Koumarelas
Energy Resources Conservation Board staff K. F. Miller J. F. Wilson, P.Eng. M. MacRae J. W. Berg, P.Eng. D. Beamer, C.E.T.	

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Decision D 84-2

ESSO RESOURCES CANADA LTD.
CONCURRENT PRODUCTION
LEDUC-WOODBEND D-3 A POOL — Application 830340

ESSO RESOURCES CANADA LTD.
GAS STORAGE
GOLDEN SPIKE D-3 A POOL — Application 830353

1 INTRODUCTION

1.1 Application 830340

Esso Resources Canada Ltd. (Esso), on behalf of the Leduc-Woodbend D-3 Unit (the Unit), applied pursuant to section 26(e) of the Oil and Gas Conservation Act to commence blowdown[1] of the Main Pool and concurrent production of oil and gas from the Saddle and Southeast Extension areas of the Leduc-Woodbend (Leduc) D-3 A Pool starting in the third quarter of 1985. Esso requested approval for a Main Pool blowdown rate of not less than 2.6 million cubic metres per day (10^6 m^3/d), with provision for a minimum blowdown rate of 1.4 x 10^6 m^3/d for the first two years from the commencement of blowdown if market conditions warrant, and increased rates beyond 2.6 x 10^6 m^3/d to maximize gas recovery and satisfy growth in market demand after two years. The location of the Main Pool, the Saddle, and Southeast (SE) Extension are shown on Figure 1. Esso supported its application with a detailed technical document in which it examined the effect of the blowdown on Leduc hydrocarbon recovery, project economics, and the effect on pools through the underlying Cooking Lake aquifer. Its technical studies were based on an initial blowdown rate of 2.6 x 10^6 m^3/d of raw gas for four years followed by a rate of 3.5 x 10^6 m^3/d (preferred rate schedule).

1.2 Application 830353

Esso also applied pursuant to section 26(b) of the Oil and Gas Conservation Act for an amendment to Approval No. 3431 to allow injection of up to 2.6 x 10^6 m^3/d of residue gas into the Golden Spike D-3 A Pool (Golden Spike Pool) during blowdown of the Leduc D-3 A Pool. The injected gas would be a combination of Golden Spike D-3 A and Leduc D-3 A Pool residue gas. Leduc gas injected would be that in excess of market demand during blowdown, and is estimated at 1.0 x 10^6 m^3/d. Esso also requested approval to convert the following Golden Spike gas producers to gas injectors:

---

[1] Blowdown refers to the concurrent production of the Main Pool gas cap and oil leg.

13-23-51-27 W4M
40-26-51-27 W4M.

The subject applications are complimentary and are intended to allow marketing flexibility for blowdown gas production from the Leduc Pool. For the purposes of hearing and decision, the two applications are considered together.

1.3 Interveners

The Leduc application was opposed in various forms by seven interveners. Four interveners have working interests in wells which are located within the Leduc D-3 A Pool but are not in the Leduc Unit. These interveners based their opposition on intrapool equity concerns. The other three interveners are operators of three neighbouring oil pools. Their opposition was based on the effects that pressure interference from the Leduc blowdown would have on their respective operations.

1.4 The Hearing

The applications were considered at a public hearing in Calgary, Alberta, on 20 and 21 September 1983, with G. J. DeSorcy, P.Eng., N. Strom, P.Eng., and F. J. Mink, P.Eng., sitting. The participants at the hearing are listed in Table 1.

2 BACKGROUND

2.1 Leduc D-3 A Pool

The Leduc D-3 A Pool is located about 30 kilometres (km) southwest of Edmonton. This historic pool was discovered in May 1947 with the successful completion of IMPERIAL LEDUC NO. 2 (1-16-50-26 W4M). The pool was largely drilled out by 1954 and a total of 535 wells have been completed in the Leduc bioherm. The pool is completely underlain by water, however, the existence of two large saddles separates the pool into three segments with the following original gas-oil and oil-water contacts:

Segment	Approx. Area (ha)	Original G/O (m subsea)	Original O/W (m subsea)
Main	7 500	908.9	920.5
Saddle	880	911.3	920.5
SE Extension	480	903.7	922.3

At the discovery pressure of 13.2 megapascals (MPa) the gas cap and oil zone volumes were approximately equal. The gas cap gas has about 17 mole per cent C_{2+} but is not a retrograde mixture. The oil zone contains a sweet paraffin base crude oil with a density of 825 kilograms per cubic metre (kg/m^3) (39° API). The initial solution gas was 98 m^3/m^3 oil and the initial quantity of solution gas in place was about one-half that of the gas cap.

The pool was on primary production until September 1955 when a pressure maintenance scheme was initiated. The method of pressure maintenance, water from the North Saskatchewan River, was unusual in that it required injection into only one well, 6-32-50-26 W4M (6-32 well). The 6-32 well was completed in a 170-m interval of water bearing reef below the Main Pool and had an injection capacity of about 10 000 m^3/d.

Gas produced with the crude oil has been gathered and conserved since July 1950. With commencement of a pressure maintenance scheme in 1955, some of the produced gas has been reinjected into the Main Pool gas cap to replace gas cap voidage and help to stabilize the position of the oil column. At the present time about 90 per cent of produced gas is reinjected.

To mid 1983, 37.8×10^6 m^3 of oil, or 96 per cent of projected ultimate recoverable oil has been produced. The Main Pool's initial oil column thickness of 11.6 m is now estimated to be less than 2.0 m. Both gas and water coning are prevalent in all Main Pool wells still capable of economic oil rates. The Main Pool gas-oil ratio (GOR) is over 1000 m^3/m^3 and the water-oil ratio (WOR) is about 5. It is estimated that the remaining oil reserves could be depleted by the mid 1990s if blowdown of the gas cap were deferred until that time. Earlier blowdown would tend to reduce the quantity and life of the remaining recoverable reserves.

2.2 The Golden Trend

The Leduc D-3 A Pool is one of the Rimbey-Meadowbrook chain of Middle Devonian reefs in Central Alberta as shown in Figure 2 (reproduced from Application 830340). The southern portion of the chain extends from the Homeglen-Rimbey D-3 Pool in the south to the St. Albert D-3 A Pool in the north. This portion of the chain is sometimes referred to as the Golden Trend because of the prolific production from its ten major oil and gas accumulations. The Devonian age reefs grew upon the western edge of the Cooking Lake carbonate platform. The reefs are dolomitized with good vugular and some intercrystalline porosities ranging from 3 to 20 per cent. The average porosity of the hydrocarbon bearing portion of the reefs range from 8 to 10 per cent. The pools have exceptional horizontal permeabilities in the order of

500 to 1500 millidarcies (md). The effective vertical permeabilities are comparatively low in the order of 5 to 100 md. In those pools where the vertical permeability is very low relative to the horizontal permeability, this phenomenon is a significant factor in retarding gas and water coning and promoting a highly efficient recovery process.

Although the individual pools along the Golden Trend are separated from each other by the overlying Ireton shale, they are in hydraulic communication through the underlying Cooking Lake aquifer which ranges in thickness from 70 to 130 m. Communication through the aquifer is restricted to the dolomitized western edge of the Cooking Lake platform. The Golden Trend reefs are in moderate to good communication with the Cooking Lake. An exception is the Golden Spike Pool which is interpreted to have poor communication with a Cooking Lake outlier which, in turn, is separated from the main Golden Trend aquifer by basinal shales.

The southern pools (Homeglen-Rimbey, Westerose South, Westerose, and Bonnie Glen) have shown interpool pressure effects which are largely unaffected by events in the northern pools (Wizard Lake, Glen Park, Leduc, Acheson, Big Lake, and St. Albert). The Cooking Lake aquifer is both thicker and broader in the region of the northern pools. Historic evidence, including the Atlantic No. 3 blowout and fresh water injection at Leduc, Acheson, and Wizard Lake, has shown that the six northern pools experience significant pressure interference. Thus, the proposed gas cap blowdown at Leduc is expected to have some effect on neighbouring pools.

2.2.1 Golden Spike

The Golden Spike Pool is a Devonian age fossiliferous limestone reef with a crestal area of some 400 hectares (ha) and an average oil pay thickness of 168 m. The pool was discovered in April 1949 with the completion of IMPERIAL SCHOEPP NO. 1 (9-22-51-27 W4M). The early production-pressure performance of the pool showed it to be a closed system isolated from the other pools on the Golden Trend. The initial oil in place of 49.6 x 10^6 m^3 was undersaturated by about 5 MPa at the discovery pressure of 14.4 MPa. The pool does not have an oil-water contact and appears to have very poor communication with the underlying carbonate platform.

The pool was on primary production until 1953 when pressure maintenance by gas injection was started. A vertical miscible flood (7 per cent hydrocarbon pore volume bank) was started in 1964. The solvent for the scheme was obtained by producing oil in excess of demand, heating it to recover natural gas liquids and returning the "de-gassed" oil to the base of the reservoir. The scheme worked reasonably well until the miscible bank encountered a previously unknown 3- to 5-m permeability barrier in 1973. The barrier extends laterally over much of the pool and occurs about midway down the reef. The barrier caused the break-up of the solvent bank with attendant dispersion into the push gas. Solvent injection was discontinued in 1976 and the current gas cycling scheme was started in 1978. The gas cycling scheme approval has a minimum pressure clause of 4.1 MPa, and with the pool pressure currently about 5 MPa, the minimum pressure is forecast to be reached in 1984 barring supplemental gas injection.

2.2.2 Wizard Lake

A hydrocarbon miscible flood was initiated at Wizard Lake in November 1969. For that project, the pool was repressured and the position of the O/W contact adjusted upward by injecting over 20 x 10^6 m^3 of fresh water. At present, some 5000 m^3/d of fresh water injection is required to maintain pool pressure at about 14.8 MPa. The miscible flood has recently been extended to include the waterflushed zone at the base of the reef and is forecast to extend the oil producing life of the pool to 1996.

2.2.3 Acheson

Pressure maintenance by fresh water injection was started at Acheson in 1957. Over 17 x 10^6 m^3 of fresh water has been injected to date. About 3500 m^3/d of fresh water is currently required to maintain pool pressure close to 11.2 MPa. Oil production is forecast to continue past 1996.

2.2.4 Other Pools

In addition to the two major pools (Wizard Lake and Acheson), there are several smaller pools which could be affected by gas cap blowdown at Leduc. The Glen Park D-3 A Pool has recovered about 80 per cent of its reserves and two structurally high wells produce the bulk of the current production. The pool is forecast to continue to produce past 1996.

The Leduc D-3 B, D-3 E, and D-3 G pools, shown in Figure 1, are at advanced stages of depletion and are forecast to cease production before blowdown would have any effect on performance or recovery.

The Leduc D-3 F Pool is a small pinnacle located on the east side of the Main Pool. It is undersaturated and contains five flowing oil wells. The cumulative oil production is over 520 000 m^3 (72 per cent of ERCB reserve estimate) and production is forecast to continue past 1990.

3 ISSUES

As the Leduc D-3 A gas cap represents a substantial gas reserve, the Board recognizes that blowdown of the gas reserve at some appropriate time is inevitable. However, the scheduling of such a blowdown operation and its various impacts must be considered. Having heard the evidence, the Board believes that the issues raised by the applications are:

- oil in place and oil recovery from the Leduc D-3 A Pool,
- gas recovery from the Leduc D-3 A Pool,
- effects on non-unit owners in the Leduc D-3 A Pool,
- the effect of Leduc blowdown on nearby pools,
- effects of gas markets on scheme implementation, and
- benefits of the scheme.

4 OIL IN PLACE AND OIL RECOVERY FROM THE LEDUC D-3 A POOL

4.1 Views of the Applicant

Esso submitted evidence supporting an increase in the Leduc D-3 A Pool initial oil in place (IOIP). Esso used a 2-dimensional, 3-phase, cross-sectional model to history match the interface movements and pressure data in the pool. To achieve a good history match, the IOIP had to be increased to 61.2×10^6 m^3. Esso suggested that the increase was not unusual due to the difficulty of estimating vugular porosity. A porosity of 10 per cent was compatible with an IOIP of 61.2×10^6 m^3, whereas the porosity had been previously estimated at 9 per cent. Esso acknowledged that the history match was not definitive with regard to the magnitude of reserves in the gas cap and a larger gas in place was possible even though the areal extent was excellently delineated.

Table 2 summarizes Esso's estimates of initial in-place oil and gas reserves including distribution among the three segments of the pool.

Using production decline analysis, Esso estimated that continuation of its present mode of operation of the Main Pool could result in an oil recovery factor for the total pool of 0.63 of the 61.2 x 10^6 m^3 IOIP. This approach to estimating recovery was considered reliable for a pool in an advanced stage of depletion.

Esso presented rate-cumulative plots for each segment of the pool and for the entire pool. It stated that all plots exhibited constant percentage declines and the ultimate recovery could be obtained by linear extrapolation. Esso supported the pool decline analysis with an analysis for an average well. For an average well in the Main Pool, a straight line extrapolation with decline rates of 15 and 17 per cent for workover and non-workover wells was evident. Coupled with an estimated decline in the number of producing wells in each category, Esso estimated the remaining recoverable reserves to be those shown in Table 3 and estimated that, if present operations (ie no gas cap blowdown) were to be continued, the total remaining oil reserves in the Leduc Pool of 1193 thousand cubic metres (10^3 m^3) would be completely recovered by 1992.

For the blowdown mode, the decline rate of producing oil wells would increase, and for this case, Esso used a coning model to estimate the remaining oil producing life. The model indicated that for a gas cap production rate of 0.2 x 10^6 m^3/d/256-ha gas well, and a liquid rate of 19 m^3/d/16-ha oil well, the oil rate would decline from 3.7 to 1.0 m^3/d/16-ha oil well approximately 1.5 years after blowdown commenced. Thus, assuming blowdown started in January 1985, the Main Pool oil production during blowdown would continue to mid 1986 and the recovery was predicted to be 119 300 m^3. (To reflect the 6- to 9-month delay in the scheme, the Board has estimated this volume to be 100 000 m^3.) As shown in Table 5, Esso estimated the Main Pool oil loss associated with its proposed blowdown to be 341 000 m^3 when compared to the recovery which would be anticipated if present operations continued.

Esso said that Main Pool blowdown would result in no loss of oil reserves of the Saddle and SE Extension areas. Gas cap production at controlled rates would stabilize the oil legs in the other two sectors and mitigate interface movements due to reduced aquifer pressure under blowdown.

4.2 Views of the Board

The Board accepts Esso's estimates of reserves in the Leduc D-3 A Pool as shown in Table 2. In particular, it accepts the increased IOIP volume submitted by Esso and the revised pool porosity of 10 per cent. The Board notes, however, that it is not possible to define whether the required changes in reserves to attain a history match are properly attributable to lower residual oil saturation (Sor) values in the invaded zones, or higher porosity. The Board believes that a similar increase in gas pool porosity may be warranted, in which case initial gas cap reserves would be greater than those shown in Table 2.

The Board believes that the applicant's decline analysis may be somewhat conservative. This would tend to underestimate the magnitude of the ultimate recoverable oil reserves if current operations are continued and also underestimate the oil loss under blowdown of the Main Pool. By using a lower decline rate for the producing oil wells in the Main Pool, the Board estimates that the loss in oil reserves could be somewhat higher.

On the other hand, the Board also believes that Esso's forecast of a 1.5-year producing life after commencement of blowdown may be somewhat pessimistic as it assumes uniform advance of the oil-water contact across the pool. The Board suspects that gas cap production from the interior of the pool could cause the oil-water contact to hump in that region, with the oil leg remaining more or less immobile for a longer time in the perimeter wells. This would tend to extend oil producing life and reduce the estimated loss under blowdown.

In summary, the Board estimates that oil recovery under the present operating mode in the Leduc D-3 A Pool would continue until 1993 with an ultimate recovery of 39 174 x 10^3 m^3 of oil (64 per cent of IOIP). The Board's estimates of the distribution of oil recovery within the Leduc D-3 A Pool sectors is shown in Table 4. Remaining oil recovery in the Main Pool is projected to be 1136 x 10^3 m^3 if present operations are continued. Also, the Board estimates the remaining oil recovery from the Main Pool would decrease to 660 x 10^3 m^3, a reduction of 476 x 10^3 m^3, for an initial blowdown rate of 2.6 x 10^6 m^3/d. The Board agrees with Esso that the remaining recovery of oil in the Saddle and SE Extension would not be adversely affected by the proposed blowdown scheme.

The Board believes there is significant uncertainty associated with forecasting oil recovery for the Main Pool during blowdown operations.

This uncertainty arises from the combination of the thin remaining oil column (1.5 m), the unpredictable performances of the aquifer under the blowdown scheme, and the presence of fully developed gas and water coning mechanisms. Notwithstanding this uncertainty, the Board believes its estimate of potential remaining oil recovery is reasonable.

5 GAS RECOVERY FROM THE LEDUC D-3 A POOL

5.1 Views of the Applicant

5.1.1 Rate Sensitivity on Gas Recovery

Esso stated that in a water drive reservoir such as the Leduc D-3 A Pool, gas recovery can be maximized by reducing the reservoir pressure to as low a level as possible. The result would be greater cumulative gas recovery before water encroached to the gas wells and lower pressure levels of residual gas entrapment by the advancing aquifer. Esso thus concluded that the optimum depletion strategy for the Main Pool gas cap would be to produce the gas at the highest practical rates that can be achieved.

The applicant noted that the production rates achievable are dependent on a number of factors: the available gas markets, water coning, gathering system and gas plant constraints, and the effect of production rate on pools in the area.

Esso proposed to maximize recovery by producing gas in excess of market requirements and storing the excess gas in the Golden Spike Pool. Its technical studies were based on a blowdown rate of 2.6×10^6 m^3/d for the first four years of operation and 3.5×10^6 m^3/d for the remaining four years of the scheme and this was designated the preferred rate schedule.

These rates represent a compromise between coning considerations, physical constraints, gas markets, and required additional fresh water injection at Acheson and Wizard Lake to offset blowdown aquifer interference effects. However, to allow for the currently depressed gas market situation, the applicant also studied the effect of a blowdown rate of 1.4×10^6 m^3/d for the first two years of operation followed by a rate of 2.6×10^6 m^3/d for the remaining six years (minimum rate schedule) on pool pressure and aquifer response.

Esso performed coning model studies to estimate gas recovery under the different rate schedules. Recoveries of 82 per cent and 78 per cent of the total gas in place were estimated for the preferred and minimum rate schedules, respectively. Gas cap recovery strictly by water drive is expected to be between 70 and 75 per cent.

Esso stated that both the minimum and preferred rate schedules would result in pressure reduction in neighbouring pools due to aquifer response to the Leduc pressure sink. Esso submitted that fresh water injection along the reef chain would adequately overcome aquifer response and maintain pool pressures. The applicant noted that although sustained low gas cap production rates averaging 1.4×10^6 m^3/d for the duration of the blowdown would result in negligible effect on neighbouring oil pools, this rate schedule unfortunately would result in Leduc D-3 A gas recovery being reduced owing to the high pressure gas entrapment effect.

5.1.2 Residual Gas Saturations

Esso used a residual gas saturation under water encroachment (S_{grw}) of 35 per cent of the pore volume for its coning model studies. This estimate was based on analyses of reservoir performance of the Westerose South and Homeglen-Rimbey D-3 A pools assuming that no unconformaties exist so that the volumetric sweep of water into the gas caps of those reservoirs is unity.

Esso analysed the sensitivity of gas cap recovery to S_{grw} and determined that a 1 per cent increase in S_{grw} would reduce gas cap recovery by less than 1 per cent. It thus concluded that the existence of nonconformities and its possible impact on the trapped gas fraction would not have a major effect on recovery.

5.1.3 Water Cycling Enhanced Gas Cap Recovery Alternative

Esso examined the possibility of retarding aquifer intrusion into the gas cap by maintaining approximately equalized pressure between the aquifer and the Leduc D-3 A Pool gas cap blowdown through an aquifer cycling scheme. Esso contended that the required rate of water cycling (2720 m^3/d) could result in an incremental gas recovery of up to 1.29×10^9 m^3 above that of its proposed blowdown scheme, but present economics would not support the project.

Esso estimated that the water cycling scheme would require capital investments of $53 million to $60 million, most of which would be required early in the life of the project. The applicant noted that, while the project appears economically viable at a discount rate of 10 per cent, typical industry values of discount rates are now in the range of 15 to 20 per cent. Esso stated that the submitted economics do not consider the potential for incremental oil recovery during cycling, as it believed that the probability of stabilizing the very thin oil column under this program was very low.

Esso submitted there were few upside possibilities to the water cycling concept, but it perceived a number of downsides. Esso indicated that a better understanding of the reservoir blowdown dynamics must be obtained to reduce the risks of project design and reservoir performance. It suggested that the economics could further be improved by an increase in gas prices, or by obtaining royalty relief for enhanced gas recovery. Esso believed that the water cycling scheme could be initiated as late as four years after the commencement of blowdown and still result in improved gas cap recovery. It therefore intended to review the technical and economic aspects of enhanced gas recovery by water cycling periodically as more is known of the reservoir dynamics.

5.2 Views of the Board

The Board considers that the 35 per cent S_{grw} estimate used by Esso in its recovery predictions is reasonable in the absence of conformance effects (Ec). However, the strength of the water drive in the Leduc D-3 A Pool could reduce conformance and result in higher gas entrapment than current expectations. While the magnitude of the trapped gas fraction was not viewed by Esso as having a major effect on gas recovery, it does represent a possible downside to blowdown recovery estimates.

The Board believes that gas recovery from the Leduc D-3 A Pool will be very much affected by residual gas entrapment pressure and by water coning at the producing wells. Generally, the higher the sustainable blowdown rate, the greater the ultimate gas recovery. On the other hand, low gas blowdown rates in the early years of the scheme could result in prolonged oil production, thereby increasing the oil recovery during the blowdown mode. The Board believes that additional oil recovery under slow initial blowdown rates must be weighed against the potential reduction in gas recovery.

Although the Board does not relate the potential level of gas recovery directly to the timing of blowdown, it sees a significant increase in demand for gas in the 1990s. Thus, if blowdown were deferred to say 1990, the gas production rates probably would not be market restrained and could be significantly higher than Esso's proposed minimum rate schedule. This would likely mean somewhat higher recovery of gas.

The Board agrees with Esso that, in view of current gas markets, price trends and the costs of water cycling, it is not economic to implement a water cycling scheme to enhance gas cap recovery at present. Also, since gas recovery under water cycling is strongly affected by abandonment pressure, it could be initiated perhaps four years after blowdown commenced and still result in significantly increased gas recovery.

6 EFFECTS ON NON-UNIT OWNERS IN THE LEDUC D-3 A POOL

6.1 Views of the Applicant

Esso recognized that the blowdown from Unit lands could cause drainage of the reserves of the non-unit lands within the Leduc D-3 A Pool. Esso contended that it had initiated negotiations with non-unit mineral rights owners and believed that arrangements to accommodate non-Unit owners could be established prior to blowdown. Esso was opposed to the blowdown approval containing any conditions respecting protection of non-unit owners, and pointed out that explicit legislation already exists to protect owner equity where drainage is purportedly occurring.

6.2 Views of the Interveners

6.2.1 Views of Tiber

Tiber Energy Corporation (Tiber) is the operator of wells located in Lsd 8-17-51-26 W4M and Lsd 9-17-51-26 W4M as shown in Figure 1. As an interest owner in the east half of section 17, Tiber is concerned that its right to equitable oil and gas production may be adversely affected if the proposed blowdown scheme is approved and initiated without mutually satisfactory arrangements between Tiber and the Unit. Tiber stated that two arrangements are being considered. The first would have the Unit operate Tiber wells and tie them into the Unit's gas gathering and treatment facilities for production of solution gas and associated liquids. The second would require either bringing the Tiber land into the Unit or a pooling arrangement with the Unit owners to allow the production of Tiber's share of the gas cap. In the absence of successfully concluding such arrangements, Tiber said that it would re-activate a currently dormant application to the ERCB to install its own facilities for gas processing and liquid recovery and apply under common purchaser legislation to ensure equitable gas cap production. Tiber therefore requested the Board to condition any blowdown approval upon its reaching a satisfactory resolution with the Unit.

6.2.2 Views of Passburg and Wilderness

Passburg Petroleums Ltd. (Passburg) and Wilderness Energy Ltd. (Wilderness) are working interest owners of a gas well at the edge of the Leduc D-3 A Pool in section 6-51-25 W4M. (Figure 1.)

Passburg was concerned that blowdown would reduce the gas reserves of the Passburg 2-6-51-25 well through gas cap drainage. Negotiations between Passburg and the Unit regarding equitable gas production are continuing but have not been finalized. Passburg requested that approval to the blowdown be conditional to an agreement being reached that would ensure protection of its interests.

Wilderness has a working interest in the Passburg well and supported the position taken by Passburg.

6.2.3 Views of Montney

Montney Resources Ltd. (Montney) supported in principle the blowdown application. Negotiations have been finalized with Esso whereby Esso will handle and, if necessary, purchase gas from the Montney's 12-31-50-25 W4M well in sufficient volumes to stabilize the oil column and maximize the oil recovery. Montney stated that its well was in a pinnacle offsetting the Main Pool (see Figure 1) and its support is conditional upon the Board granting good production practice (GPP) status to oil production from the pool. Application for GPP has not been made.

6.3 Views of the Board

The Board notes that the Unit is endeavouring to establish voluntary agreements with non-unit owners that would avoid equity problems during blowdown. Failing such arrangements, the Board believes that the existing common purchaser legislation is the appropriate means for protection of the interests of Tiber and Passburg (Wilderness). In the event that voluntary agreements are not in place at the time of blowdown, the Board assumes that these issues would be brought before it under the common purchaser legislation. The Board therefore does not agree that a condition to the approval is necessary for the protection of non-unit gas interests in the Leduc D-3 A Pool.

The Board believes that Montney's 12-31 well is in the Leduc D-3 A Pool. Respecting the recovery of potential oil reserves on the Tiber and Montney lands, the Board notes that apart from the requirements respecting gas conservation, oil may be produced without restriction from these lands, as is available to the Unit. While the Board accepts that an agreement that would allow for the processing of production from the Tiber lands through the Unit facilities may be most cost effective, it considers the matter to be a question of business arrangements between two parties. Failing that, legislation exists which might provide a remedy. In any case, the Board does not believe that it has jurisdiction to condition a blowdown approval in the manner suggested by Tiber.

7 THE EFFECT OF LEDUC BLOWDOWN ON NEARBY POOLS

7.1 Peripheral Pinnacle Reefs

7.1.1 Views of the Applicant

Esso's technical basis for the application assumed commencement of blowdown of the Main Pool at the start of 1985. The applicant, since the time of conducting its studies, revised this date to be the third quarter of 1985. Although this represents a 6- to 9-month delay, Esso considered the application is still fully consistent with the technical studies and its perception of gas markets.

The timing of the blowdown is of importance to the depletion plans in adjacent D-3 pools. The location of the adjacent Leduc pinnacles with respect to the Leduc D-3 A Pool is shown in Figure 1. Esso's studies showed that the blowdown would result in pressure reductions in the adjacent Leduc D-3 pinnacles and in Acheson and Wizard Lake pools.

The Leduc D-3 C and D-3 D pools are abandoned. The oil reserves of the D-3 B and D-3 G pools were forecast by Esso to be depleted by 1987, and it stated that the 1985 blowdown would have essentially no effect on operation or oil recoveries obtainable from those pools. Esso observed that the Leduc D-3 E and D-3 F pools would not be fully depleted before the effects of blowdown are felt.

The Leduc D-3 E Pool is an undersaturated oil pool with a fully developed gas cap. Similar to the D-3 A Saddle and SE Extension areas, Esso believed that concurrent gas and oil production from the D-3 E Pool would result in no loss of oil reserves during Main Pool blowdown.

Esso noted that gas cap production is a feasible method of obtaining oil reserves from the saturated oil pools affected by the Main Pool blowdown. Esso stressed that accelerated production of oil reserves prior to blowdown would enhance the possibility of maximizing oil recovery.

Esso contended that the reduction in pressure caused by blowdown would increase the recoverable reserves of the D-3 F Pool. Its model studies indicated that by reducing the reservoir pressure below the bubble point, the oil column would swell due to the solution gas evolution and realization of an assumed critical gas saturation of 10 per cent. Esso stated that improved oil displacement efficiency could thereby be obtained in a water-drive reservoir by the effect of substituting residual gas for residual oil. Results of the model studies indicated that this mechanism would increase the recovery of the D-3 F reserves by 6 to 9 per cent. Although limited reservoir data made the model results inadequate for determination of reserves, Esso believed the results are directional in nature and indicated some level of increased reserves. As 60 per cent working interest owner in the D-3 F Pool, Esso stated that it would prefer to avoid reducing the oil reserves of the D-3 F Pool.

Table 5 summarizes Esso's estimates of the effect that blowdown would have on oil recoveries from D-3 pools in the Leduc-Woodbend Field. Esso concluded that the 1985 blowdown mode would not result in significant loss of oil in the adjacent pools.

7.1.2 Views of Ladd

Ladd Exploration Company (Ladd) stated that blowdown of the Leduc D-3 A Main Pool would result in a decrease of oil reserves in the Leduc D-3 F Pool due to a reduction in reservoir pressure caused by the blowdown. Using a 2-dimensional radial model with a critical gas saturation of 4 per cent, Ladd determined that oil reserves would actually be reduced by 4 per cent, principally owing to the effect of the anticipated pressure reduction on well producing life. As in the Esso models, the results were considered directional in nature and not sufficiently definitive to estimate reserves. Ladd noted that it is standard industry practice to produce undersaturated reef-type oil reservoirs by maintaining reservoir pressures above the bubble point.

Ladd contended that since Esso proposed to share the cost of injecting fresh water at Acheson and Wizard Lake to negate the effect of the blowdown on those pools, it would be similarly consistent for Esso to compensate the D-3 F operators for any adverse blowdown effects. However, any compensation would require a definitive analysis of the effect of blowdown on the D-3 F oil reserves. In Ladd's view, this would be a 3-phase, 3-dimensional history matching simulation to be performed by an independent body. Ladd concluded that unless GPP is granted immediately, the 3-phase, 3-dimensional study should be performed to determine compensation. Ladd noted that although requesting compensation for interpool effects is unusual, it is consistent with the situation at Acheson and Wizard Lake.

Ladd further stated that blowdown would result not only in reduced reserves, but also in increased capital and operating costs of artificial lift equipment required due to diminished well inflow performances.

As an alternative to compensation by Esso, Ladd had applied to the Board for GPP in the D-3 F Pool. It was generally satisfied that revenue from accelerated production rates would adequately compensate the D-3 F Pool owners. In conclusion, Ladd requested that approval of the Leduc D-3 A Main Pool blowdown be conditional to immediate approval of GPP for the D-3 F Pool, or that a program of compensation based on an independent study of the effects of blowdown on the D-3 F oil reserves be established by the Board.

7.1.3 Views of the Board

Respecting the D-3 F Pool, which is located near the proposed gas cap blowdown wells, the Board believes the impact would be rapid and would tend to reduce recovery efficiency. The Board agrees with Ladd that the most cost-effective way of avoiding the potential adverse effect would be rapid depletion. Considering the possibility of early blowdown and primarily in the interest of avoiding loss of oil recovery from the D-3 F Pool, the Board immediately subsequent to the hearing assigned GPP for all the small pinnacles close to the Unit, including the D-3 F Pool.

7.2 Effect on the Acheson and Wizard Lake D-3 A Pools

7.2.1 Views of the Applicant

Esso studied the effect of Leduc D-3 A Main Pool blowdown on the operations of the Acheson and Wizard Lake D-3 A pools and concluded that with adequate aquifer support no adverse effects would occur at those pools. The proposed aquifer support would involve supplemental fresh water injection into the Cooking Lake aquifer at strategic locations in the Wizard Lake and Acheson D-3 A pools. Incremental water injection would have to be in sufficient volumes to maintain Wizard Lake and Acheson reservoir pressures as required in their respective enhanced recovery schemes.

Esso stated that the optimization of hydrocarbon resource recovery from any pool is the responsibility of the operator of that pool. Given that the Leduc D-3 A blowdown would have an effect on that recovery, Esso was currently negotiating agreements to share in costs incurred in providing the required additional fresh water injection at Acheson and Wizard Lake. Esso objected to proposals by Chevron Canada Resources Ltd. (Chevron) and Texaco Canada Resources Ltd. (Texaco), the operators of these pools, that approval for Leduc blowdown be withheld until agreements are reached for the supplemental water injection. However, Esso testified that it would not be opposed to a condition requiring it to satisfy the Board that it had pursued all efforts to provide for supplemental water injection before being allowed to proceed with blowdown operations. Also, Esso observed that if a successful agreement is not reached, those concerned operators have recourse through the Oil and Gas Conservation Act.

7.2.2 Views of Chevron

Chevron supported the application in principle, but was concerned with the potential impact on the Acheson D-3 A pressure maintenance scheme in absence of adequate incremental water injection to overcome aquifer response. Chevron stated that it has reached an agreement in principle with Esso as to the sharing of water injection responsibility. However, it urged the Board to condition the approval pending final agreement between the two parties. Chevron stated that an unconditional approval could weaken its negotiating strength. Chevron argued that while possibilities of recourse exist under sections 24 and 91 of the Oil and Gas Conservation Act, the outcome of such recourse is very uncertain.

7.2.3 Views of Texaco

Texaco was also concerned about the potential adverse impact on its miscible flood enhanced recovery operation in the Wizard Lake D-3 A Pool during blowdown of the Leduc D-3 A Main Pool and in the absence of adequate incremental water injection at Wizard Lake. Texaco and Esso have initiated negotiations regarding the shared responsibility for the incremental water injection. Notwithstanding those discussions, Texaco requested that because of the critical importance to the overall integrity of the miscible flood, the Board withhold approval of the blowdown scheme until negotiations have been successfully finalized.

7.2.4 Views of the Board

The Board agrees that Leduc Main Pool blowdown could cause significant pressure reductions in the Acheson D-3 A and Wizard Lake D-3 A pools. However, the Board notes that both the applicant and interveners agreed that incremental fresh water injection at Acheson and Wizard Lake could overcome the pressure interference caused by the blowdown.

Considering the advanced state of negotiations and the delayed start-up of the blowdown, the Board is satisfied that the parties have adequate time to reach a suitable arrangement for the incremental water injection. The Board holds the view that agreements for incremental water injection must be in place by the time blowdown gets underway in order to prevent serious loss in oil recovery, especially at Wizard Lake. To this end the Board would, if necessary, pursue "show cause" proceedings to ensure that the necessary facilities were installed at Acheson and Wizard Lake.

In conclusion, the Board agrees with Esso that the owners in a pool have a basic responsibility to ensure efficient resource conservation for that pool. At the same time, in this particular situation, it is evident that Esso can ensure that there will be no delay or future interruption of its blowdown scheduling by sharing in the needed water injection facilities. The Board accepts that Esso is strongly motivated to expedite these programs. Therefore, the Board will only ask Esso to confirm that the agreements are in place prior to the commencement of blowdown.

8 EFFECTS OF GAS MARKETS ON SCHEME IMPLEMENTATION

8.1 Views of the Applicant

Taking into account the effects of gas entrapment by encroaching water and pressure of entrapment, Esso recognized the dependence of the ultimate recovery of gas on the sustained rate at which the gas is produced during blowdown. It concluded that blowdown of the Main Pool should proceed only when sufficient assured gas markets have been established. Esso pointed to potential markets at Cold Lake and Judy Creek that it would regard as "internal" markets, these being proprietary to Esso. Esso stated that it had been negotiating on its own behalf over the last nine months to secure an "external" market that would support its minimum rate schedule and that it would continue to search for markets that are supportive of the preferred rate case. Nevertheless, Esso's basic position was that, even in the absence of external markets, it had sufficient internal markets available to start the blowdown.

Esso stated that it was negotiating contracts for its portion of the Unit production of approximately 83 per cent. Esso also stated that, based on indications from the potential purchasers and historical experience, a contract offered to and accepted by Esso would likewise be offered to the remaining Unit participants. Esso stated that it would also offer to purchase the other Unit participants' production if Esso's internal markets had to be utilized.

Esso also submitted that it had investigated export markets and local utility markets as potential external markets. Esso stated that negotiations were proceeding and that it could foresee an external market in 1985 ranging from 0.6 to 1.1 x 10^6 m^3/d expanding to 2.1 x 10^6 m^3/d of residue gas during 1987 or 1988. Converting to a raw gas volume, Esso stated that the 2.1 x 10^6 m^3/d rate corresponds to a raw gas production rate of 2.6 x 10^6 m^3/d. Recognizing that the gas market was somewhat uncertain in the short term, Esso proposed to utilize the gas storage surge capacity in Golden Spike to accelerate the blowdown and thereby increase ultimate gas recovery. Esso submitted that the Golden Spike Pool would require make-up gas by 1985 for pressure maintenance in any event and proposed to store up to a maximum of 1.0 x 10^6 m^3/d as a means of balancing the blowdown rate and the available market. With the additional storage volume, Esso planned to use Golden Spike surge production capacity to satisfy the peaking requirements of future external markets. In contract negotiations, Esso stated that its scheme for integration of Leduc blowdown and Golden Spike surge storage was designed to provide as much flexibility as possible in load factors and required sales volumes to make the gas more attractive to the purchaser and thereby enhance the securing of the external markets.

Esso submitted that its marketing plan would be to utilize its own internal market for the Leduc D-3 A blowdown production if external markets did not develop. In support of this, Esso submitted the disposition of its internal market as shown in Table 5. Esso stated that its internal market would become available in early 1986 and the total gas requirement would be 2.1 x 10^6 m^3/d on a residue gas basis, adequate to support the higher blowdown rate.

Esso stated that it would require the lower rate of 1.4 x 10^6 m^3/d initially to allow the appropriate staging of markets to occur. With regard to its internal market, Esso stated that it was reluctant to enter into a situation where it would be offering a gas contract at discounted prices to other Unit participants.

8.2 Views of the Board

The Board notes that significant loss of gas recovery would occur if the production rate is significantly curtailed at any time after the initiation of blowdown, including that which may derive from lack of demand and a cutback in contract rates. For this reason, the Board considers the security of markets as an important consideration in determining the merit of the proposed scheme.

The Board notes that Esso has an internal market to support production rates significantly higher than those of its minimum rate schedule. A market of this nature would represent a continuous base load and provide the needed security in a rate-sensitive scheme. The Board also notes the applicant's reluctance to utilize these markets where it is the only buyer and primary seller of gas from the Unit. The Board realizes that external markets would be preferable to the applicant particularly in today's market situation.

The Board does not regard the applicant's proposed external market as offering the same security as its internal market although it does expect export markets to start to improve after 1989.

In summary, the Board is concerned that the blowdown rate not be subject to serious fluctuation and significant overall curtailment by market conditions. Considering the lead time to secure markets, the applicant's flexibility to use some gas for its own internal purposes, and the ability to store over one-third of the total Leduc blowdown gas production in Golden Spike, the Board expects the applicant to ensure firm disposition of Leduc gas to allow for sustained blowdown at rates conducive to maximum gas recovery. The Board considers the application as an undertaking by Esso to do so.

With regard to the Golden Spike application, the Board notes that pressure maintenance will be required in the pool during 1984. The Board believes that the pool is a suitable reservoir for the storage of the volumes of gas proposed by Esso. The Board further notes that the Golden Spike application was not addressed by the interveners. In summary, the Board believes that the storage of Leduc gas in the Golden Spike Pool is an appropriate means of providing pressure support and offers a unique opportunity for the gas marketing and gas conservation of the Leduc blowdown gas.

9 BENEFITS OF THE SCHEME

9.1 Views of the Applicant

Esso stated that since the late 1970s, an economic benefit to both Esso and the province could be realized through the sale of residue gas and natural gas liquids from Main Pool gas cap production.

The applicant submitted that the economic crossover point at which time the value of gas cap production is greater than the value of the remaining oil reserves occurred in the late 1970s as shown in Figure 3 (reproduced from Application 830340). It estimated that at the optimum date of blowdown (1982) the incremental value of the blowdown scheme is approximately $200 million in excess of the value of continuing with the present operations. The studies by Esso showed that continued oil production without blowdown beyond 1984 results in a lost opportunity to maximize revenue for both industry and the government. Accordingly, Esso stated that present worth economics should now take precedence over oil conservation. The applicant also justified the reduced oil recovery by the economic benefits to industry and government gained through gas cap production.

Esso noted that the 1985 blowdown would be very timely for gas and ethane requirements at its projects such as Cold Lake and Judy Creek, as well as other miscible flood projects in the province. It indicated that the use of natural gas liquids from Leduc in miscible flood schemes will recover more tertiary oil than the predicted oil lost due to the Leduc blowdown.

Esso also contended that engineering and construction companies will benefit at a time of poor economic activity from the $45 million in investment associated with the project. The applicant further noted that the abandonment of up to 450 wells at Leduc would increase service rig activity and return these abandoned well sites to agricultural and residential uses.

9.2 Views of the Board

The Board agrees with Esso that the cash flow from the pool would be increased by the proposed blowdown scheme. The Board's studies confirm the economic conclusion by the applicant that the commencement of blowdown in 1985 would result in maximizing the revenue from the recovery of all hydrocarbons from the pool and would represent an incremental value of some $200 million to the industry and government. The Board also believes that implementation of the blowdown in 1985 would assist the service industry at a time when normal activity is expected to be somewhat depressed.

The Board's studies show that the loss of oil recovery would decline from a maximum 476 000 m^3 if blowdown commenced in 1985 to nil if blowdown was delayed until 1993. The Board's estimate of loss in oil recovery with commencement of blowdown in successive years is shown in Figure 4. While the economic factors favour the immediate and rapid blowdown of the gas, the Board is also concerned about the potential loss of oil.

The Board recognizes that studies carried out by Esso conclude that it would be in Esso's best interest to advance the blowdown to begin in 1985 largely because the value of produced gas at an early date more than offsets the value of the oil. It is not certain from the evidence that the economic benefit from maximizing revenues would be shared by the public sector. These conclusions respecting economics depend largely on the assumptions made about the ultimate recovery of oil during blowdown, the outlook for oil and gas prices, the available markets, and the disposition of gas and products produced during the blowdown.

Having regard for all factors, the Board is satisfied that the increased present worth value and the other positive economic impacts outweigh the loss of oil that will occur. It is thus prepared to approve the blowdown scheme.

The Board believes that lower levels of gas production in the initial phase of blowdown would extend and increase the production of oil without having any material effect on gas recovery. This measure would aid in the conservation of oil with only a modest economic effect. Given the present uncertainty in the gas market, it may also be of some benefit to delay the addition of significant volumes of new gas supply. Accordingly, the Board favours a lower level of gas blowdown in the initial years to extend the life of the oil leg and assist oil conservation, followed by maximum practical gas production rates in time to avoid adverse impacts on the recovery of gas.

10 FINDINGS AND CONCLUSIONS OF THE BOARD

The Board has given due consideration to all the foregoing factors and has reached the following set of conclusions:

- Esso's IOIP estimate and the resulting increase in oil zone porosity is appropriate and the Board has adopted the estimate.

- Without blowdown, oil production from the Leduc D-3 A Pool would continue until late 1993.

- The Board's estimate of the recoverable oil lost due to a blowdown in the Main Pool starting in the third quarter of 1985 is 476 000 m^3.

- The recovery of oil under the proposed scheme can be increased by initiating the blowdown at a low rate.

- The amount of trapped gas can be minimized by depleting the gas cap at the highest practical rates.

- A sustained rate of 3.5×10^6 m^3/d during the middle and late stages of depletion would provide for optimum gas-cap recovery.

- The recovery of gas under the proposed scheme is not materially altered by reduced initial gas blowdown rates to year-end 1987.

- An initial gas production rate of 1.4×10^6 m^3/d to year-end 1987 would produce less aggravation to the present provincial gas marketing situation.

- Enhanced gas recovery by water cycling the aquifer would increase the recoverable gas by approximately 1×10^9 m^3 and would tend to reduce the rate sensitivity of gas recovery under any blowdown scheme.

- Present industry economics do not support the water cycling scheme.

- The water cycling scheme can benefit gas recovery as late as four years after the initiation of blowdown.

- The remaining unresolved equity issues within the Leduc D-3 A Pool are protected by the existing legislation and it is not necessary to condition the permit in order to protect the correlative rights.

- The acceleration of oil production by granting GPP to the pinnacle reefs immediately adjacent to the Leduc D-3 A Pool will minimize the potential lost oil reserves in those pools and satisfy the concerns of the pool operators.

- The proposed blowdown would have a significant negative impact on the hydrocarbon recoveries in the Wizard Lake and Acheson D-3 A pools should the necessary measures for incremental water injection at these pools not be taken, and therefore, the Board will require Esso to confirm that satisfactory measures have been taken to prevent the adverse effects on those pools prior to commencement of blowdown.

- The proposed blowdown starting in the third quarter of 1985 is timely considering the economic benefits to the applicant, government, and the public sector.

- The Golden Spike Pool is suitable to store surplus natural gas during the blowdown of the Leduc D-3 A Pool.

11 DECISION

The Board grants Application 830340 subject to the following conditions:

(a) The initial raw gas production rate from the Main Pool as designated in Figure 1 shall be 1.4 x 10^6 m^3/d on an average annual basis for a period extending to year-end 1987, after which the minimum raw gas production rate shall be 3.5 x 10^6 m^3/d on an average annual basis until the end of the project.

(b) The applicant shall satisfy the Board prior to commencement of blowdown that adequate markets have been secured to sustain the approved rate of blowdown.

(c) The applicant shall confirm with the Board that agreements are in place to install facilities for the incremental water injection into the Acheson and Wizard Lake D-3 A pools prior to the commencment of blowdown.

(d) The applicant shall submit to the Board two biennial reports in 1986 and 1988 on the economic viability of slowing water advance into the reservoir by aquifer cycling.

The Board also grants Application 830353 for the storage of gas in the Golden Spike D-3 A Pool, subject to approval by the Minister of the Environment in matters pertaining to the environment.

DATED at Calgary, Alberta, on 16 January 1984.

ENERGY RESOURCES CONSERVATION BOARD

GJ DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

N Strom

N. Strom, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Resources Canada Ltd. (Esso) J. B. Ballem, Q.C. T. Hughes	R. D. Knowles, P.Eng. R.H.G. Millar, P.Eng. R. J. Rodgers, P.Eng. G. L. Barfoot, P.Eng. B. A. Dawe, P.Eng.
Chevron Canada Resources Ltd. (Chevron) D. G. Guest	
Texaco Canada Resources Ltd. (Texaco) D. Guise, P.Eng.	
Ladd Exploration Company (Ladd) J. Mracek, P.Eng.	A. A. Abdalla, P.Eng. P. Pantella, P.Eng. A. Zia, P.Eng.
Tiber Energy Corporation (Tiber) H. R. Ward	D. P. Petursson, P.Eng. G. James, P.Geol.
Passburg Petroleums Ltd. (Passburg) S. Hobbs	
Wilderness Energy Ltd. (Wilderness) K. H. Hayes, P.Eng.	
Montney Resources Ltd. (Montney) R. H. Johnson, P.Eng.	
Energy Resources Conservation Board staff Dr. R. A. Purvis, P.Eng. J. P. Werth, P.Eng. C.J.C. Page H. R. Keushnig, P.Eng. R. J. Cox, E.I.T.	

TABLE 2 ESSO'S ESTIMATES OF RESERVES IN THE LEDUC-WOODBEND D-3 A POOL*

Pool Segment	IOIP 10^6 m	Solution IGIP 10^9 m^3	Gas Cap IGIP 10^9 m^3	Total IGIP 10^9 m^3
Main	50.4	4.91	11.27	16.19
Saddle	6.0	0.58	0.30	0.88
SE Extension	4.8	0.47	0.30	0.77
Total	61.2	5.96	11.87*	17.83

* ERCB adopts the submitted estimates but notes that IGIP may prove to be higher by virtue of higher porosity.

TABLE 3 ESSO'S ESTIMATE OF OIL RECOVERY IN THE LEDUC-WOODBEND D-3 A POOL

Pool Segment	Production to 31 Dec 82 10^3 m^3	Existing Mode (1 Jan 83 to 1 Oct 93) Remaining 10^3 m^3	Blowdown Mode (1 Jan 83 to 1 Apr 87) Remaining 10^3 m^3
Main	31 432	963	622
Saddle	3 290	115	115
SE Extension	2 911	115	115
Total	37 633	1 193	852

TABLE 4 ERCB ESTIMATES OF OIL RECOVERY IN THE LEDUC-WOODBEND D-3 A POOL

Pool Segment	Production to Dec 82 10^3 m^3	Existing Mode (1 Jan 83 to 1 Oct 93) Remaining 10^3 m^3	Blowdown Mode (1 Jan 83 to 1 Apr 87) Remaining 10^3 m^3
Main Pool	31 432	1 136	660
Saddle	3 290	186	186
SE Extension	2 911	219	219
Total	37 633	1 541	1 065

TABLE 5 ESSO'S ESTIMATE OF POTENTIAL OIL LOSSES FOR THE LEDUC D-3 POOLS ADJUSTED FOR BLOWDOWN COMMENCING 1 OCTOBER 1985

	Oil Production To 31 Dec 1982 (10^3 m^3)	Depletion Date	Oil Reserves from 1 Jan 1983 (10^3 m^3)				Difference in Remaining Reserves (10^3 m^3)	
Area/Well			Without Blowdown		With Blowdown			
D-3 A - Main	31 200	1992	963		622		341	
Saddle	3 300	1992	115		115		0	
SE Extension	2 900	1992	115		115		0	
D-3 A Pinnacle Sec 3, 10-51-26	131	1988	51		50		1	
D-3 B	1 168	1987	2.3		2.3		0	
D-3 C	73.7	Abandoned	0				0	
D-3 D	44.3	Abandoned	-				0	
D-3 E	9.3	1987	6.1		6.1		0	
D-3 F	505	1994	215		227		(62)	
D-3 G	13	1988	3.6		3.6		0	
D-3 H	0	1992 est	61		61		0	
A-Tiber Sec 17-51-26	0.49	SI 1992	0	9.0*	0	5.5*	0	3.5*
Yeske 16-35-50-26	92	1990	3		2		1	
Aberford 15-23-50-26	105	1993	8.5		5.7		2.8	
Passburg 2-6-51-25	0	SI 1992*	0	3.2*	0	2.0		1.2
							283.8	288.5

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* Well not producible due to high GOR.

TABLE 6 DESCRIPTION OF ESSO'S INTERNAL MARKET FOR GAS

Market Location	Gas Rate (10^6 m^3/d)	Timing
Cold Lake	0.6 - 1.2	Early 1986 (possibly as high as 2.1 x 10^6 m^3/d by 1989)
Judy Creek	0.7	Early 1986
Other (Edmonton Refinery, etc)	0.8	Early 1986
Total	2.1 - 2.7	

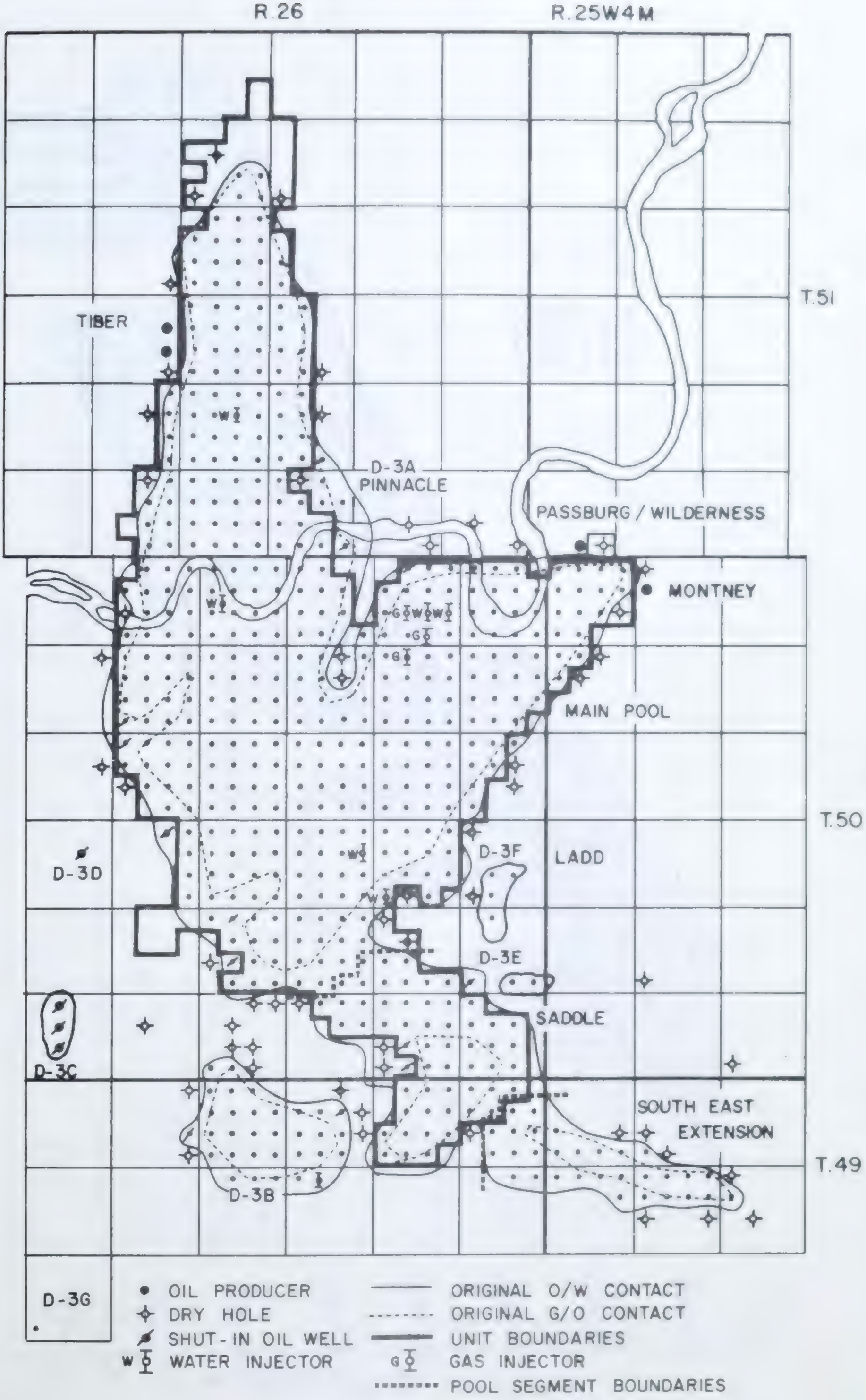

FIGURE 1: LEDUC D-3 POOLS

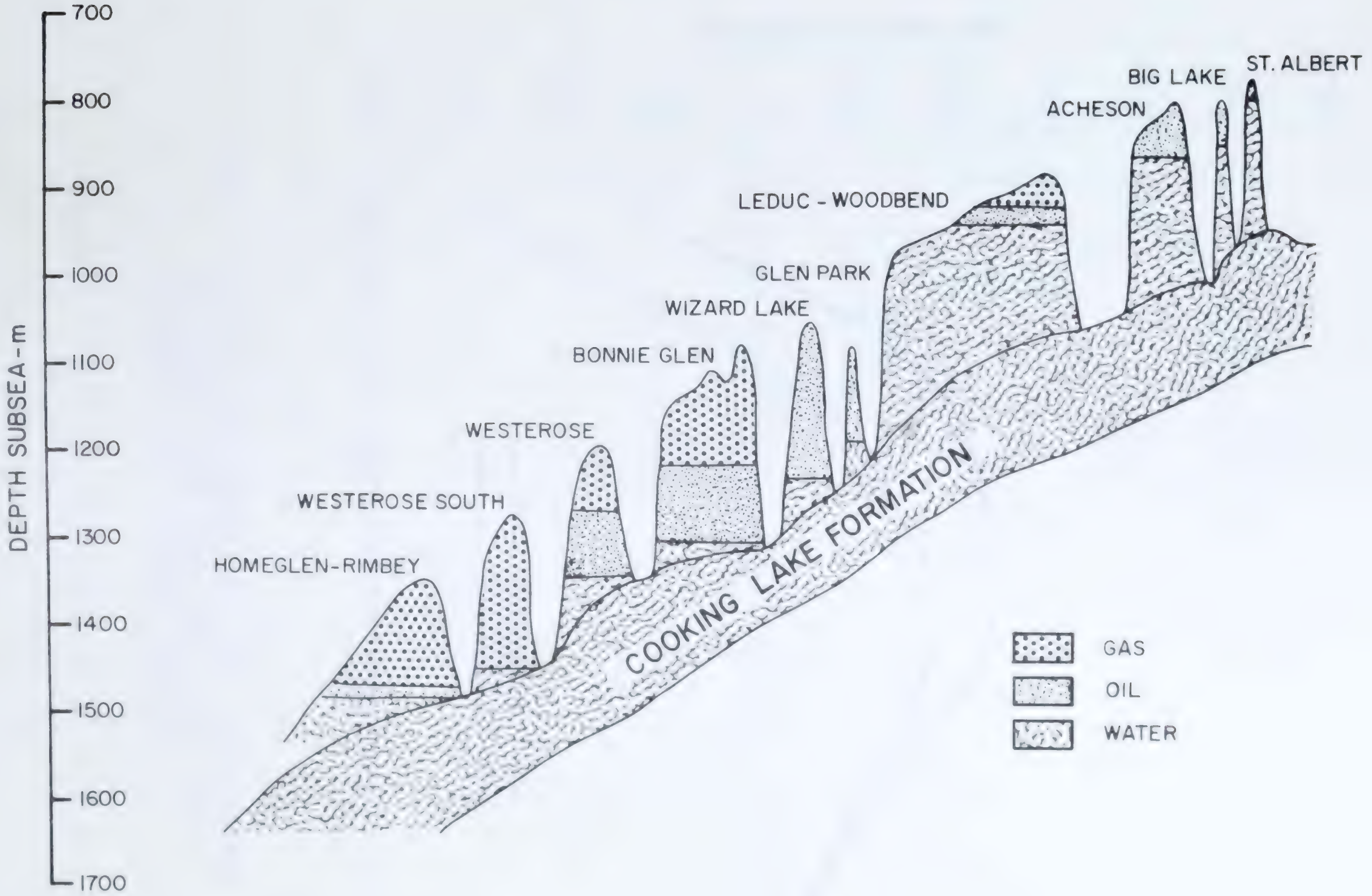

FIGURE 2: COOKING LAKE AQUIFER CROSS SECTION.

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ERCB

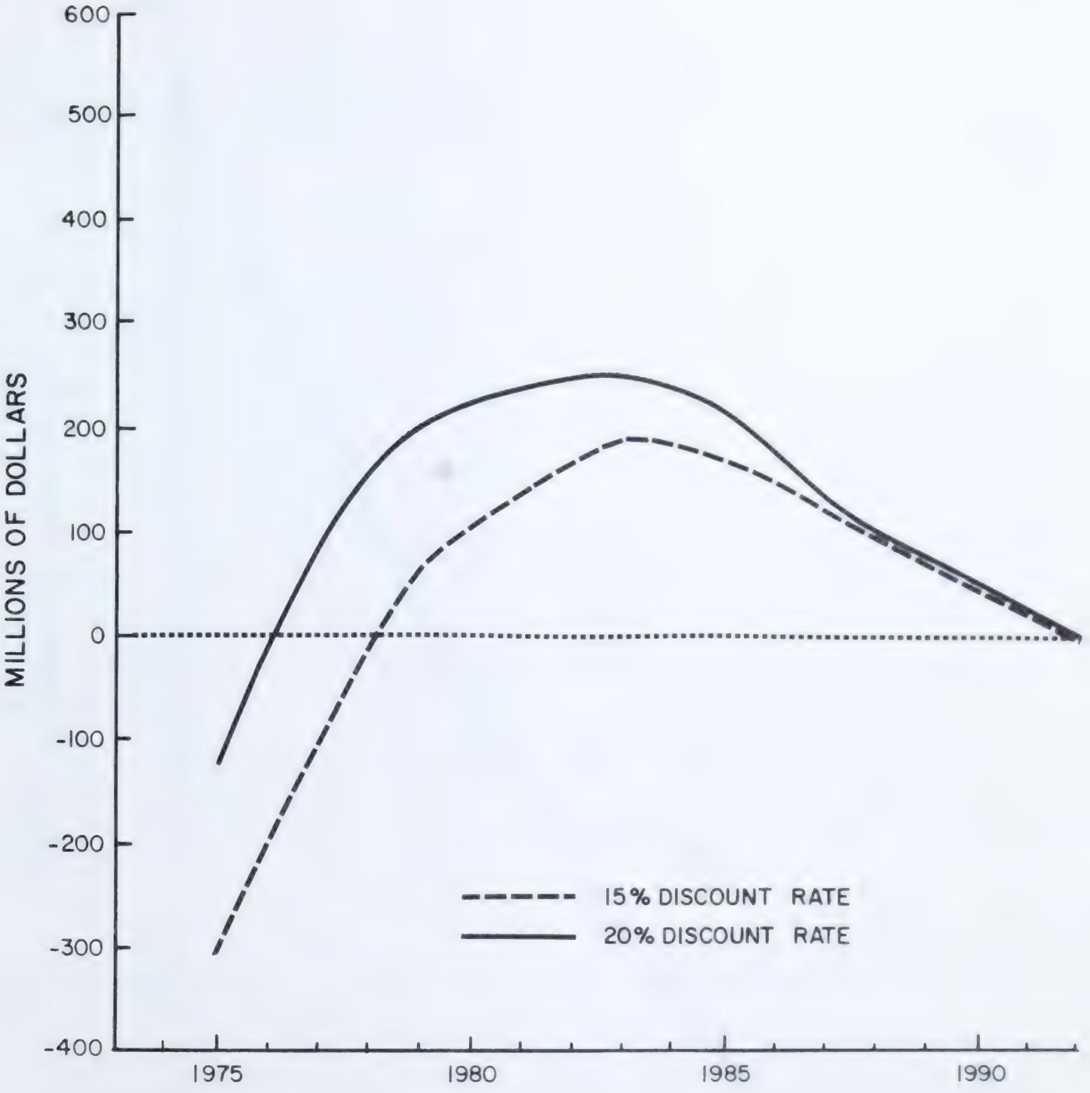

FIGURE 3: ESSO'S ASSESSMENT OF THE ACCELERATED VALUE OF LEDUC D-3A MAIN POOL GAS CAP. CURRENT YEAR PRESENT WORTH.

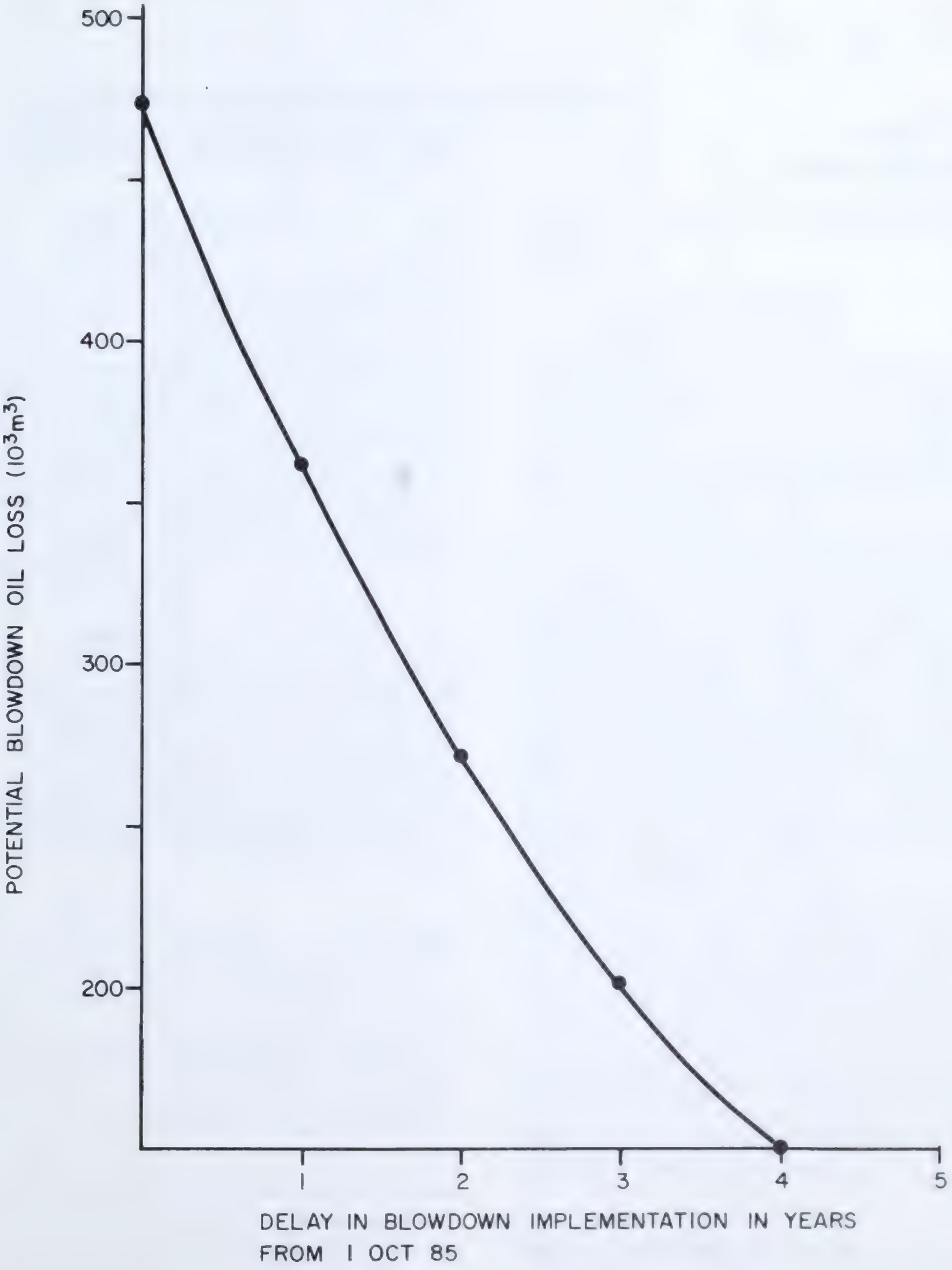

FIGURE 4: THE BOARD'S ESTIMATE OF THE REDUCTION OF RECOVERABLE OIL LOSSES WITH DELAYED BLOWDOWN SCHEME START-UP.

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

WESTERN DECALTA PETROLEUM (1977) LIMITED DIAMOND VALLEY GAS PROJECT TURNER VALLEY FIELD AND AREA

Decision D 84-3
Application 831044

1 INTRODUCTION

1.1 The Application

Western Decalta Petroleum (1977) Limited (Western Decalta) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct a gas processing plant to be located at one of two suggested sites in the Hartell area south of Turner Valley, as shown on the attached figure. The applicant's preferred site for the proposed Diamond Valley gas plant is in Lsd 10-12-19-2 W5M (Site A), where Suncor Inc.'s shut-down Hartell gas plant is presently located. Western Decalta also requested that an alternative plant site at Lsd 10-8-19-2 W5M (Site B), be considered.

1.2 The Hearing

The application was considered at a public hearing in Turner Valley, Alberta, on 1 February 1984, with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and T. F. Homeniuk, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table. Home Oil filed an intervention and appeared at the hearing to support Western Decalta's application. The Crown intervened for purposes of cross-examination only.

1.3 Background

Western Decalta's Turner Valley gas plant, located within the Town of Turner Valley, has been processing gas since 1925. Its current operating licences, which expire on 1 May 1985, allow a maximum of 1127 thousand cubic metres per day (10^3 m^3/d) of raw gas to be processed from which 1099 × 10^3 m^3 of sales gas, 84 m^3 of propane, 60 m^3 of butanes, 207 m^3 of pentanes plus, and 23.7 tonnes (t) of sulphur can be recovered.

The plant has a licensed minimum sulphur recovery efficiency level of 86.0 per cent with an estimated sulphur dioxide (SO_2) emission of 6.2 t/d (3.1 t/d equivalent sulphur)[1] from the incinerator stack.

Operation of the Turner Valley gas plant would be discontinued and the plant de-commissioned when operation commenced at the proposed Diamond Valley gas plant.

2 THE PROPOSED PLANT

2.1 Evaluation of Alternatives

Western Decalta stated that it had considered various alternatives for processing gas from the Turner Valley area after the Turner Valley gas plant's operating licences expire in 1985. These included upgrading the present plant, transporting the gas to another plant, and constructing a new plant.

The existing plant is old and obsolete, and substantial expenditures would be required to upgrade it to meet current standards. The plant is inefficient with respect to sulphur recovery, energy utilization, cooling water use, and liquids recovery. Western Decalta's economic analyses indicate it would be more profitable to construct a new facility than to continue operation of the existing plant, even if it were upgraded. Additionally, the location of the existing plant in the town of Turner Valley is increasingly considered to be environmentally and socially unacceptable. For these reasons, Western Decalta ruled out upgrading the existing plant.

Western Decalta identified a number of reasons why it chose not to transport Turner Valley area gas to other plants such as Esso's plant at Quirk Creek, Canterra's plant at Okotoks, or the Canadian Occidental Mazeppa plant. These included lower net cash flows to the producers, greater risk to producers with respect to control over processing fees, load shedding[2], liquids recovery, marketing related matters, the need for new sour gas pipelines and related rights of way, and minimizing displacement and disruption of present operating staff.

2.2 Site Selection

Western Decalta identified a number of possible sites for the proposed plant, however, it was able to obtain a purchase option for only the Suncor Hartell plant site, Site A. It included a site that it owned, Site B, as an alternative location for the proposed plant.

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[1] Sulphur dioxide is a compound formed from equal weights of sulphur and oxygen. Therefore, the estimated daily emissions can be described as being equal to either 3.1 tonnes per day of sulphur or 6.2 tonnes per day of sulphur dioxide.

[2] Load shedding refers to a reduction in the amount of gas processed by a plant due to a lack of gas markets.

The applicant stated that it preferred Site A because the proposed Diamond Valley plant would occupy the same location as the shut-down Suncor Hartell plant. This would result in an overall project cost reduction of approximately $2 million because some existing equipment, buildings, and foundations would be used, site preparation requirements would be minimized, and no new access road or upgrading would be required. Additionally, less agricultural land would be removed from production than at Site B, and residential density is considerably lower near Site A than at Site B. The only significant disadvantage associated with Site A is that longer product and raw gas pipelines would be required compared to Site B. However, Western Decalta claimed that disturbances associated with pipeline construction would be short term, and other impacts would be minimized by utilizing existing and common rights of way to the greatest extent possible.

2.3 Plant Size

Western Decalta stated that the Diamond Valley plant would process the gas now being processed at the Turner Valley plant and any other gas from producers in the area, all of whom had been canvassed for nominations of gas quantities for the plant. The amount of gas in the Turner Valley area that is available for processing is declining and the new plant's maximum quantities would be only half those volumes that the existing plant once handled. Western Decalta stated it would seek a 20-year term for the plant operating licence.

The Diamond Valley gas plant would be designed to process a maximum of 563.5×10^3 m^3/d of raw sour gas containing approximately 1.47 per cent hydrogen sulphide (H_2S), from which 429.9×10^3 m^3 of sales gas, 178.0 m^3 of ethane, 130.4 m^3 of propane, 85.2 m^3 of butanes, and 51.0 m^3 of pentanes plus would be recovered. Of the maximum of 11.2 t/d of sulphur contained in the raw inlet gas, Western Decalta proposed to recover a minimum of 95.0 per cent of this inlet sulphur (10.7 t/d of liquid sulphur would be recovered). The remaining annual average 0.56 t/d of sulphur in the form of SO_2 would be emitted to the atmosphere through an incinerator stack 40 metres (m) in height.

2.4 Environmental Features

The 40-m incinerator stack was selected to meet Alberta Environment's requirements for maximum SO_2 ground-level concentrations. Western Decalta stated that, even taking into account any plume overlap from the Esso Quirk Creek and Canterra Okotoks plants, the overall maximum SO_2 ground-level concentrations would be 0.15 and 0.16 parts per million (ppm) for Site A and Site B respectively, compared to Alberta Environment's one-hour average concentration objective of 0.17 ppm under worst-case meteorological conditions. During emergency flaring of the inlet and acid gas streams, appropriate fuel gas volumes would be added to ensure air quality objectives are met.

The recovered liquid sulphur would be stored on site in storage facilities and then trucked to market. There would be no solid sulphur block storage or source of sulphur dust at the plant site.

Western Decalta stated that the proposed plant would require 8.0 m^3/d (1.22 gallons per minute) of water which would be utilized for domestic purposes. The plant itself would be air cooled and would differ significantly in this respect from the existing plant which is water cooled. Western Decalta proposed to obtain approval from Alberta Environment to use the water from an existing well at Site A.

The applicant stated that plant-site surface run-off water would be directed to holding ponds. Prior to any necessary release to the area watershed, this water would be analysed and treated to conform to Alberta Environment guidelines. Process water produced at the plant along with liquid wastes would be trucked to an existing water injection well for disposal.

Western Decalta stated that present background noise levels in the area near the proposed sites are approximately 35 and 40 decibels (dBA) for Site A and Site B respectively, and are considered typical of rural areas in the summer. The main source of noise at the plant would be the compressors and cooling fans which would be new equipment and would be based on a design requirement that noise from this equipment would not exceed 50 dBA at the plant site boundary.

3 INTERVENERS' SUBMISSIONS

B. Mosby filed a submission supporting the relocation of the Turner Valley gas plant. However, he expressed a concern regarding the effect of the lost tax base on the town. He suggested that existing pipelines should be rerouted into a corridor, thus freeing up some of the rights of way for development and recovery of a portion of the lost tax base. He did not speak to his submission at the hearing.

G. Noble, whose property adjoins Site A, opposed the site on the basis that his property value would decrease, the plant water well might draw water from aquifers in the area and thereby affect existing farm water supply wells, and the possibility of plant buildings being constructed immediately adjacent to his fenceline. He contended that the proposed plant should be constructed closer to the raw gas supply.

The Wyatts, whose property also adjoins Site A, agreed that Site A would be appropriate for the proposed plant, but were concerned that their land would decrease in value, use of rental land would be lost, and with possible health hazards to residents and cattle. They stated concerns about grass fires caused by liquid spills from the flare stack and questioned the adequacy of the on-site well as a water supply for plant operation including fire fighting. Other concerns included building material discarded onto their land, buildings next to their fenceline, possible road widening, and trespassers.

The residents of the Hartell area intervened in favour of Site A. They were opposed to Site B because of the large number of residents living in close proximity to this site. They were concerned with gas plant emissions, the plant's disruption of residents' view of the mountains, and the noise from the proposed facility. They also stated that the Hartell area has a severe shortage of water and were concerned about the water supply for Site B.

The Tongue Creek area residents would be affected by the choice of either Site A or B. They were opposed to the number of sour gas plants being built in close proximity to one another in the populated area south of Calgary. They contended that the presence of a plant within an agricultural area would be an intrusion in a rural setting and would devalue their land. They reiterated the concerns of other interveners about area water supplies, weed control, and noise levels during plant construction and operation. They submitted that many of these issues and future complaints could be dealt with through close community contact by the applicant but expressed additional concerns that they said could not be handled through this method. These concerns included heavy traffic on Highway 543 and the poor location of the turning lane into Site A. The group requested that future plans be developed to handle emergency situations and compensation in the event of pipeline ruptures, fires, product spills, and future corrosion problems.

To satisfy health concerns of the residents, the Tongue Creek group requested that a minimum 97.0 per cent sulphur recovery efficiency level be guaranteed by the applicant. The interveners contended they were not asking for a recovery level higher than the plant was capable of achieving.

4 APPLICANT'S RESPONSE TO INTERVENERS' SUBMISSIONS

In response to B. Mosby's concern that the numerous existing pipelines would be an impediment to surface land development by the Town of Turner Valley, Western Decalta expressed a willingness to meet with the intervener, town administrators, and the companies who own the pipelines to explore the possibility of rerouting the pipelines into a corridor.

Western Decalta stated that it had considered the effect that sour gas facilities might have on land values in the Municipal District of Foothills and had reviewed a previous study of selling prices for lands around sour gas plants in Southern Alberta. This study showed that the presence of gas plants in an area did not affect the selling price of properties near the plants. Western Decalta contended that the value of agricultural land is based on its productivity and that the proposed Diamond Valley plant would have no adverse effect on the productivity of the surrounding land. It therefore concluded that construction and operation of its proposed plant would not reduce property values in the area.

Western Decalta agreed that a new three-stage Claus process could achieve the 97.0 per cent efficiency level requested by the Tongue Creek residents. However, the existing Suncor Hartell three-stage Claus sulphur plant was built in 1971 and significant modifications to the existing sulphur recovery facilities would have to be made to ensure a 95.0 per cent sulphur recovery level. Modifications to ensure a sulphur recovery efficiency level of 97.0 per cent would cost an additional $300 thousand.

The applicant stated that, under normal operating conditions, it expected to achieve a sulphur recovery efficiency higher than the 95.0 per cent it was applying for. However, because the plant can be expected to operate occasionally under upset or unusual conditions, it could not guarantee a higher level than 95.0 per cent over a year-long period.

Western Decalta stated that the quantity of sulphur that would be emitted from its proposed plant at a 95.0 per cent sulphur recovery level, compared to the interveners' suggested 97.0 per cent efficiency level, is an important consideration. The higher efficiency level would recover only an additional 220 kilograms per day (485 lb/day) of sulphur. Therefore, the additional expenditure of $300 thousand would only reduce the proposed plant's daily sulphur emissions to 0.34 t/d from the proposed 0.56 t/d.

Western Decalta emphasized that its applied-for sulphur recovery efficiency level of 95.0 per cent for the Diamond Valley gas plant was a significant improvement over the 86.0 per cent recovery presently being achieved by the existing Turner Valley plant and pointed out that its proposed 95.0 per cent level would exceed the 94.6 per cent recovery requirement of IL 80-24[3]. Furthermore, based on an expected average sulphur inlet rate of 8.0 t/d, as compared to the plant design sulphur inlet of 11.2 t/d, the proposed sulphur recovery efficiency level of 95.0 per cent would give the Diamond Valley gas plant one of the highest sulphur recovery levels in the province for plants of this size.

Regarding the interveners' concerns about possible deterioration of air quality due to the plant's emissions, Western Decalta stated that operation of the Diamond Valley gas plant, and shutting down of the Turner Valley plant, would actually create certain environmental benefits in the area. The higher sulphur recovery efficiency would lower the present sulphur deposition rates in the region. As a result, Western Decalta argued, the impact of its proposed plant on air quality would be positive. The applicant acknowledged, however, that there would be a minimal increase in sulphur deposition in a relatively small area downwind of the proposed gas plant. Based on results it obtained from a model used to calculate sulphur deposition from the proposed plant at Site A, Western Decalta predicted that maximum sulphur deposition, at a rate of 2.2 kilograms per hectare annually (kg/ha/a) (about 2 lb per acre per year) would occur in an area about 3 kilometres (km) southeast of Site A. The application emphasized that this calculated maximum sulphur deposition value was appreciably less than the recognized global background value of about 5.0 kg/ha/a, which is generated by natural sources such as seaspray and volcanic activity, as well as existing industrial emission sources.

Western Decalta concluded that there would be no measurable adverse impact on existing air quality in the area nor would sulphur deposition increase in the region as a result of its proposed Diamond Valley gas plant.

On the issue of possible depletion of the local freshwater aquifers, Western Decalta stated it would make application to Alberta Environment for approval to license and use the existing water-supply well on Site A to provide the plant with a required volume of 8.0 m^3/d. (This water usage equates to a consumption rate of about 1760 gallons per day.) The applicant affirmed that this required volume of water would be for domestic purposes only. Western Decalta outlined that the Diamond Valley plant would be air-cooled in contrast to the existing Turner Valley plant which utilizes a once-through water cooling system that circulates approximately 20×10^3 m^3/d (approximately 4.4 million gallons per day) of cooling water out of and back into the Sheep River. The applicant said it believed the on-site water well could supply the plant's water requirements for the life of the project and would have no effect on domestic water wells in the surrounding area. Western Decalta outlined, however, that if it was precluded from using the on-site well as a source for water, or if this well became an inadequate source, it would investigate alternative sources to ensure the plant's water supply.

In response to interveners' questions regarding water being available to extinguish possible fires at the proposed plant, the applicant stated it would control such fires with dry chemical fire fighting equipment that would be kept on the plant site. Additionally, it could obtain water to combat fires from the proposed plant's holding ponds.

With respect to the interveners' concerns regarding additional truck traffic in the area of the proposed plant, the applicant explained that a daily average of four truck loads of product would be transported from the plant as compared to two loads which now move through Turner Valley. Western Decalta stated that to accommodate this increase in product transport, as well as the traffic generated by its plant employees, it would explore mitigative measures such as turning lanes and traffic controls when it met with municipal authorities, and undertook to address these issues when it applies to the Municipal District of Foothills for a development permit for the plant.

In response to questions about its emergency procedures plan and communication with community members, Western Decalta outlined the information it conveyed to area residents about its proposed facility. The applicant contended that through open-house presentations and informational letters, it had provided community members with details about the proposed plant's size, type of gas to be processed, plans for environment protection, noise abatement, and the safety of local residents. Western Decalta said it would be modifying the emergency procedures plan which exists for its Turner Valley plant and, following Board approval of its new plant, it would convey the details of the plan to area residents. The applicant contended that it had made a major commitment to a public communication program and indicated it intended to meet periodically with area residents to address matters of interest and alleviate possible concerns. Notwithstanding its commitment to have an approved emergency procedures plan in place, Western Decalta stated it could not foresee any emergency situation which would require the evacuation of local residents.

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[3] Energy Resources Conservation Board, 1980. *Sulphur Recovery Guidelines — Gas Processing Operations*. ERCB Informational Letter IL 80-24. Calgary, Alberta.

With respect to possible corrosion, Western Decalta suggested that it would be extremely difficult to determine that such problems were the result of plant emissions. However, if indeed this could be determined, the applicant said it would consider compensating those individuals who incurred property deterioration due to corrosion.

The applicant committed to responding and correcting any odour or weed problems that might result from the construction and operation of its proposed plant. Similarly, it confirmed that it would respond to any other plant related concerns that might be brought to its attention by the local area residents.

5 BOARD'S VIEWS

The Board agrees that the obsolete facilities at Western Decalta's Turner Valley gas plant place severe limitations on efficient plant operation. Also, current environmental and social guidelines for construction and operation of a sour gas plant would make it very difficult to reconstruct the plant at its present location when its current operating licences expire in 1985. The Board therefore concludes that operation of a gas plant at the site of the Turner Valley plant should not be continued beyond 1985.

The Board has considered the plants identified by the applicant as possible locations for processing Turner Valley area gas. In its view, Esso's Quirk Creek plant may not operate continuously and interruption of the processing of Turner Valley area gas would necessitate flaring of solution gas at oil batteries in the Turner Valley area. The Canterra Okotoks plant and the Canadian Occidental Mazeppa facility are both designed for gas containing a much higher H_2S content. In addition, since all plants are located a long distance from Turner Valley, long sour gas pipelines would need to be constructed. The Board concludes that constructing a new plant in the Turner Valley area is the preferred alternative.

The Board notes that the applicant determined the design capacity of the plant based on a decline in availability of gas from the Turner Valley area after canvassing all other producers for nominations prior to setting the plant capacity. The Board accepts that the plant size is suitable and that a 20-year operating life would appear appropriate.

In comparing the two sites proposed by the applicant, the Board notes that Site A has already undergone initial disturbance and is occupied by the Suncor Hartell plant. Some road work but no new roads would be required, site preparation would be substantially less than at Site B, an existing plant would be utilized, and fewer individuals reside near Site A than Site B. The Board recognizes the many concerns and impacts identified by area residents but believes that these can be mitigated and made acceptable. In this regard, the Board acknowledges Western Decalta's commitment to maintain communications with the community residents and to respond to their concerns. The Board is satisfied that Site A is a more appropriate location for the proposed Diamond Valley plant than is Site B.

The Board notes that predicted impacts of plant emissions on the surrounding land would be minimal, and finds the basis for estimating background sulphur deposition rates acceptable. Also, the applicant intends to monitor soil pH, to check for possible soil acidification in accordance with Alberta Environment's requirements. The applicant would be required to situate prescribed stationary air monitors and sulphation stations in strategic areas in close proximity to the proposed plant site to monitor the ambient air.

The Board finds the factors and considerations used by the applicant to estimate impact on air quality, and more specifically for predicting sulphur emission levels in the area, are conservative and accepts that the predicted levels indicate a marginal benefit to the region over what exists with the present Turner Valley plant.

The Board agrees with the applicant's request for approval of a minimum 95.0 per cent sulphur recovery efficiency level to meet the requirements of IL 80-24, to accommodate possible limitations of the modified equipment, and to account for plant operating fluctuations. The Board notes that the cost of equipping the plant to achieve a 97.0 per cent recovery efficiency level would be some $300 thousand and that the actual difference in the amount of sulphur recovered at a 97.0 per cent level compared to a 95.0 per cent is relatively minor, some 0.22 t/d. The Board agrees with the applicant that the extra expenditure is not warranted in this case, given the insignificant increase in sulphur recovery. The Board notes that Western Decalta would be amenable to the Board requiring a higher level of sulphur recovery efficiency by the Diamond Valley gas plant if demonstrated as practical after a reasonable period of operation. The Board believes it would be appropriate initially to approve a sulphur recovery level of 95.0 per cent, which exceeds the 94.6 per cent requirements of its guidelines, and, if a higher level can be demonstrated based on actual operating experience, the recovery should be re-evaluated.

The Board notes that use of the water well at Site A would require relicensing by Alberta Environment and believes that related concerns would be dealt with at that time. Even if the water well proved to be unsuitable, the Board is satisfied that another source would be available, either by piping or hauling in a supply.

Similarly, concerns relating to traffic would be better addressed when the applicant applies to the municipal authority for approval of the development. In any event, the traffic problem is not so serious as to rule out the suitability of Site A for the plant.

The Board notes the applicant's considerations for noise, possible odours, fire, and weed control, and views the commitments of Western Decalta to a program of continued contact with area residents as a desirable method for resolving these issues and handling possible future complaints.

6 DECISION

Having considered the evidence of the applicant and interveners, the Board believes that the proposed gas processing plant is in the public interest.

The Board concludes that the most appropriate location for the plant is Site A.

The Board will require the plant to recover 95.0 per cent of the sulphur in the inlet gas as an initial recovery level. After two years of plant operation, the Board will review the operating history of the plant to determine whether a sulphur recovery level higher than 95.0 per cent should be required.

The Board is prepared to approve the application subject to receipt of approval of the Minister of the Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 29 February 1984.

ENERGY RESOURCES CONSERVATION BOARD

Bohme

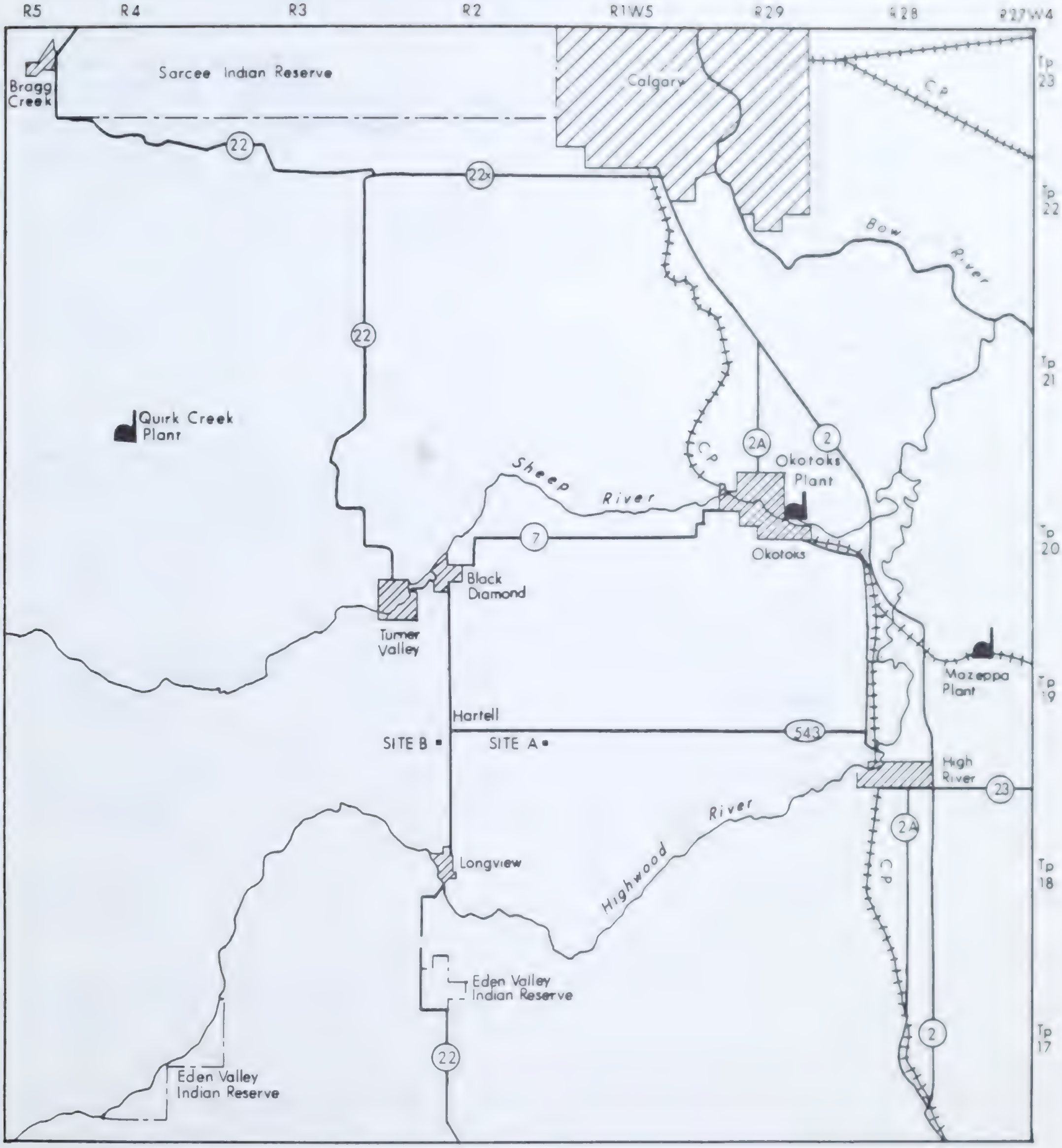
V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

THomeniuk

T. F. Homeniuk, P.Eng.
Acting Board Member



WESTERN DECALTA PETROLEUM (1977) LIMITED
APPLICATION NO. 831044
TURNER VALLEY REGION AND OTHER AREA GAS PLANTS

FIGURE TO DECISION D84-3

ERCB

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Western Decalta Petroleum (1977) Limited (Western Decalta) H. D. Williamson	A. R. Lambden, P.Eng. L. A. Shier, P.Eng. Dr. D. M. Leahey* G. Latonas* * of Western Research, Division of Bow Valley Resources Services Ltd. Y. C. Lim, P.Eng.** B. R. Comber, P.Eng.** ** of Monenco Engineers & Constructors Inc.
Home Oil Company Limited (Home Oil) B. Vanrootselaar, P.Eng.	B. Vanrootselaar, P.Eng.
B. A. Mosby	
G. F. Noble	G. F. Noble
Tongue Creek Area Residents (Site A Residents) B. Harty	B. Harty D. orrison J. Miller
Hartell Area Residents (Site B Residents) D. E. Mulder	D. E. Mulder
S. and D. Wyatt B. and I. Wyatt S. Wyatt	S. Wyatt
Her Majesty the Queen in Right of Alberta (the Crown) C. S. Liu, P.Eng.	
Energy Resources Conservation Board staff D. A. Holgate M. Semchuck, C.E.T. M. A. Francis, C.E.T.	

Calgary Regional Planning Commission filed a submission but did not appear at the hearing.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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Decision D 84-4

GASCAN RESOURCES LTD. ENHANCED RECOVERY MITSUE GILWOOD A POOL

APPLICATION 830996

CHEVRON CANADA RESOURCES LIMITED AMENDMENT TO BOARD APPROVAL 3665 ENHANCED RECOVERY MITSUE GILWOOD A POOL

APPLICATION 831212

1 INTRODUCTION

1.1 Background

The Mitsue Gilwood A Pool (the Pool) is a large oil pool located approximately 200 kilometres (km) north-northwest of Edmonton. This largely oil bearing reservoir is confined between an aquifer along the western flank and three small associated gas caps located updip in the southeast end of the Pool.

The Pool is situated at the updip pinchout of the Gilwood sandstone, a member of the Watt Mountain formation of Middle Devonian age. The depositional model theorized for the Gilwood is that of a fluvial environment trending northwest-southeast, with two major pulses of sand into the area resulting in Upper and Lower Gilwood sand units. The upper unit has a significant component of pebbly sands indicating the higher energy of deposition typical of a braided stream. The lower sands were the result of a lower energy system of meandering streams. The upper sands were deposited in channels which occasionally scoured into the lower sands causing communication. Depositional dip is "up" toward the source (northwest) but also "up" in a radial manner to the north and east from the core of the Mitsue Field.

Discovered in 1964, the Pool produced under primary depletion until 1968 when it became apparent that the Pool could not be efficiently depleted through the natural water influx from the aquifer. The Pool was unitized in 1968 as the Mitsue Gilwood Sand Unit #1 (the Unit) with Chevron Canada Resources Limited (Chevron) as Unit operator.

The Unit initiated a scheme for oil recovery enhancement by fresh water injection involving a line drive pattern along the western flank. However, in the absence of sufficient pressure support in the updip regions of the Pool, many wells experienced high gas-oil ratios (GORs) and the production from these wells was restricted. The Unit has amended the scheme on numerous occasions to provide additional water injectors.

The Pool now includes the Unit and some 42 non-unit wells. These latter primary producing wells have been drilled since 1968 and most are located on the updip edge of the Pool (see Figure 1). By 1981, at least one third of the active wells in the primary depletion area of the Pool had producing GORs in excess of the Pool's GOR penalty base indicating a need for pressure maintenance. With inflated allowable allocations, the GOR penalty base provided little control over excess gas production. In response to this problem, the Board issued IL 81-20 requesting operators of primary wells, either individually or collectively, to investigate the feasibility of oil recovery enhancement for their tracts. The Board also set a maximum rate limitation (MRL) of 10 cubic metres per day (m^3/d) for all primary areas to offset the potential adverse impact on the existing Unit scheme of high reservoir voidage due to high gas production in the primary areas. The Board also requested the primary owners to include a feasibility study on the conservation of gas from their production.

In addition to the Unit's scheme, only one other scheme for oil recovery enhancement in the Pool has been approved by the Board. Operated by Gascan Resources Ltd. (Gascan), the scheme consists of an injector in Lsd 5-5-73-5 W5M and a producer in Lsd A2-27-73-5 W5M (the A2-27 well), which are approximately 8 km apart and separated by Unit lands.

In this previous application by Gascan, Chevron objected to the scheme on the grounds that it did not contain whole contiguous drilling spacing units (DSUs) and therefore the scheme could not satisfy section 5.160 of the Oil and Gas Conservation Regulations (Regulations) with regard to qualifying as a project. In addition, Chevron objected on equity grounds and on the lack of continuity between the proposed injector and producer. Following Board approval, Chevron filed an appeal with the Alberta Court of Appeal contending that:

> "The Energy Resources Conservation Board erred in that it approved a scheme for the enhanced recovery of oil in the Mitsue Gilwood A Pool which could result or alternatively did result, in a project on the said pool containing two non-contiguous drilling spacing units in violation of paragraph 5.160 of the Regulations passed pursuant to the Oil and Gas Conservation Act".

The Court dismissed Chevron's appeal on the basis that the approved scheme need not necessarily lead to the recognition of project status by the Board. In its ruling, the Court expressed the opinion that "a drilling spacing unit may constitute a project" and that the Board could grant project status to a scheme consisting of discontinuous DSUs "where unique circumstances exist" under the existing legislation.

1.2 Applications and Interventions

1.2.1 The Gascan Application (Application 830996)

Gascan, on behalf of itself and its working interest owners, applied pursuant to section 26(a) of the Oil and Gas Conservation Act (the Act) for approval of two schemes for enhanced recovery of oil by water injection in the Pool. The general area of the application is shown on Figure 2. Gascan proposed to inject fresh water into a well proposed for Lsd 14-4-69-3 W5M (the 14-4 well) and to produce from two updip wells located in Lsd 15-10-69-3 W5M (the 15-10 well) and Lsd 4-27-69-3 W5M (the 4-27 well). Gascan also requested that the Board consider the suitability of the 15-10 well for water injection as an alternative to the 14-4 well. Gascan submitted that in the event the 15-10 well watered-out prior to drilling the 14-4 well, it would apply for an amendment to replace the 14-4 injector with the 15-10 well.

1.2.2 The Chevron Intervention

Chevron, as operator of the offset pressure maintenance scheme, filed an objection stating that:

- Any resulting projects would not contain whole contiguous DSUs as required by section 5.160 of the Regulations.
- Gascan would not be able to control the performance of the proposed schemes.
- Equity would not be preserved between the two parties as the proposed producers, particularly the 4-27 well, would produce mostly Unit oil.
- The approval of the proposed schemes would result in a proliferation of similar schemes in the Pool that would not provide "economic, orderly and efficient development in the public interest of the oil, gas and crude bitumen resources of Alberta" — one of the stated purposes of the Act (Part 1, 4(c)).

1.2.3 The Chevron Application (Application 831212)

Chevron, as operator of the Unit, applied pursuant to section 26 of the Act for an amendment to Approval 3665 to permit conversion of the well, ATLANTIC MITSUE 2-22-69-3 W5M (the 2-22 well), to fresh water injection service (see Figure 2). Chevron supported its application by an evaluation of the need for injection to the lower sand unit and by presenting the results of its simulation study that predicted an increase in cumulative oil recovery due to water injection at the 2-22 well.

1.2.4 The Gascan Intervention

Gascan, as operator in the southwest quarter of section 27 and the northeast quarter of section 10, both of township 69, range 3, west of the 5th meridian, filed an objection to the Chevron application and stated that:

- Conversion of the proposed well to water injection may be less beneficial in providing the desired pressure support to producing wells exhibiting abnormal GOR behaviour than would injection into a more suitable location.
- The information provided by the applicant was insufficient to enable Gascan to assess the impact of the flood front advancement from Lsd 2-22-69-3 W5M on either of the two Gascan producing wells in Lsd 15-10-69-3 W5M and Lsd 4-27-69-3 W5M.

1.3 The Hearing

The applications were considered at a public hearing in Calgary, Alberta, on 18, 19, and 20 January 1984, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting. The participants are listed in the following table.

The applications were considered at a single proceeding due to the possible impact each had on the other and due to the need for reviewing information common to both applications. Similarly, a single decision report was deemed appropriate.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Chevron Canada Resources Limited (Chevron) J. Stein, Q.C.	R. A. Filgate, P.Eng. A. R. Bamsey, P.Eng. C. Sproule-Matieshin, P.Eng. D. N. Schierman, P.Eng. D. Rees
Gascan Resources Ltd. (Gascan) A. L. McLarty	J. S. Artindale, P.Eng. L. D. Mann, P.Eng. H. W. Goodman, P.Geol.
Energy Resources Conservation Board staff C.J.C. Page A. R. Mustafa J. P. Werth, P.Eng. R. J. Willard, P.Eng.	

A THE GASCAN APPLICATION

In the matter of the 15-10 well, the Board views the suitability of injection at this well as the subject of a possible future application and will consider the merit of the present application based on the schemes as described, ie, injection at the 14-4 well and production at the 15-10 and 4-27 wells.

2 THE ISSUES

Having heard the evidence, the Board believes the issues relating to the Gascan application to be:

- The need for consideration of project status.
- The need for voidage replacement to enhance oil recovery.
- The effectiveness of communication between the proposed injector and producing wells.
- The ability to control the performance of wells in the schemes.
- Possible alternative schemes to enhance oil recovery in the region of the 4-27 well.
- Possible proliferation of similar schemes and the potential impact on Pool recovery.
- The opportunity of each owner to obtain its share of production from the Pool.
- Controls for performance monitoring, in the event the application is approved.

3 THE NEED FOR CONSIDERATION OF PROJECT STATUS

3.1 Views of Gascan

Gascan submitted that its application was not made pursuant to section 5.160 of the Regulations and that the question of project status should be addressed at a future time. It stated that if an application for project status were presented at a later date, it would be Gascan's position that each of the two specific productive properties would be a single project entity wholly contained within the 64-hectare (ha) DSU attributable to that specific tract.

3.2 Views of Chevron

Chevron acknowledged that there was a distinction between a scheme and a project and that the application was for two enhanced recovery schemes. Chevron submitted that projects follow schemes and that the Board has to consider its own Regulations in dealing with this application because, as a result of its decisions, monies could be spent on schemes which might fail to qualify as projects at a later date.

Chevron expressed the view that there was strong purpose, relating to equity in a pool, underlying the requirement in section 5.160 of the Regulations for projects to consist of whole contiguous DSUs and recommended that the Board not deviate from this requirement. In addition, Chevron stated that the Board should not approve a scheme if it knows it cannot become a project or that, in order to make it a project, the Board would have to make an exception to section 5.160.

Chevron submitted that a scheme cannot exist with production wells only and that the 14-4 location must be considered as part of the proposed schemes and future projects. Chevron concluded that the proposed schemes did not contain contiguous DSUs and did not meet the project requirements of section 5.160 of the Regulations. Chevron thus recommended that the Board deny approval of the proposed schemes.

3.3 Views of the Board

The Board is satisfied that the process for obtaining project status for any enhanced oil recovery scheme is clear in the Act and Regulations. A scheme for enhanced recovery must first be approved by the Board. Second, the scheme must perform satisfactorily to demonstrate that it is effective in enhancing oil recovery. Finally, upon application for project status, the Board may establish a project if it is satisified that operations are proceeding in accordance with the scheme.

The Board does not agree with Chevron's argument that it must consider the issue of whether the proposed schemes can become projects under the Regulations in the consideration of the proposed schemes. The Board notes that a scheme need not become a project as the Board has no way of anticipating the actual effectiveness of a scheme or the form of an application for project status, should one be made. In the Board's view, it would be improper to consider a possible project status for the proposed schemes at this time. If there is a possibility that a subsequent request for project status would not be approved, that is a risk that the applicant must accept.

4 THE NEED FOR VOIDAGE REPLACEMENT TO ENHANCE OIL RECOVERY

4.1 Views of Gascan

Gascan stated that pressure maintenance was already occurring at both the 15-10 and 4-27 wells due to the water injection at the Unit wells in Lsd 8-4-69-3 W5M (8-4 well) and Lsd 8-9-69-3 W5M (8-9 well). However, the applicant stressed that the Unit was under no obligation to maintain pressure in Gascan's tracts and hence there was a need for additional injection to balance voidage in the area of its tracts.

Gascan submitted that it had not conducted its own study to determine the magnitude of oil recovery enhancement in the Pool resulting from its proposed schemes. Pointing to the strategic location of the 4-27 well, Gascan concluded that downdip injection would enhance oil recovery as the Unit did not have the capability to recover the updip reserves in the area of the well.

4.2 Views of Chevron

Chevron stated that voidage replacement in the Pool was necessary to ensure maximum oil recovery but acknowledged that at present there is no obligation on the Unit to replace the voidage of the primary producers.

Chevron opposed the application on the grounds that the proposed scheme would not enhance oil recovery from the Pool but rather was designed to increase the production from the 4-27 and 15-10 wells, thereby promoting migration of oil from the Unit area. According to Chevron's estimate, Unit oil would contribute about 99.9 per cent of the oil that would be recovered from the 4-27 well over its remaining life. Chevron acknowledged that the Unit could limit the amount of oil migration off Unit lands by drilling an offsetting producer to the 4-27 well. Chevron stated that such a decision would be made dependent upon the related future economic benefit. Chevron also observed that the proposed scheme would enhance recovery in the north half of section 27, where the oil would be trapped once the waterflood front had encountered the 4-27 well.

4.3 Views of the Board

The Board believes that full replacement of voidage caused by primary production from the Pool is necessary to enhance oil recovery. For this reason, the Board issued IL 81-20 directing operators of the primary wells to make submissions respecting enhanced oil recovery operations for their lands.

The Board agrees with Chevron that the proposed scheme would result in fluid migration in the highly permeable upper zone channel towards the 4-27 well. The Board believes, however, that the Unit has the opportunity to limit the amount of off-Unit migration through the addition of updip wells. The Board notes that with the present well density, the reserves north of the Unit wells in 10-21 and 2-22 would remain unrecovered by the Unit once the waterflood front has passed those wells.The Board also notes that Chevron could not guarantee that the Unit would pursue these reserves as that would depend on a future economic decision. The Unit also is not in a position to guarantee replacement of production from the 15-10 and 4-27 wells, nor is the situation such that the Board could place such an obligation upon the Unit.

In summary, the Board concludes that full voidage replacement is desirable, the Unit has no obligation or right to do so on behalf of Gascan, and, provided that the proposed 14-4 well encounters the Pool as prognosticated by Gascan, the schemes will likely enhance oil recovery from the Pool. This would be due, in part, to the favourable structural position of the 4-27 well. The Board notes that the reserves in the north half of section 27 are not proven and thus the question of enhanced oil recovery in this area need not be addressed at this time.

5 THE EFFECTIVENESS OF COMMUNICATION BETWEEN THE PROPOSED INJECTOR AND THE PRODUCING WELLS

5.1 Views of the Applicant

Gascan submitted that the 4-27 well was in effective communication with the downdip Unit injectors in Lsd 8-4 and 8-9-69-3 W5M (the 8-4 and 8-9 wells, Figure 2). The applicant pointed to a pressure increase at the 4-27 well of 1000 kilopascals (kPa) between 1982 and 1983 corresponding to the injection at the 8-9 well as conclusive proof of communication. Accompanying the pressure increase, Gascan observed a drastic reduction in the producing GOR. The applicant stated that the 8-4, 8-9, and 4-27 wells were completed in the Upper Gilwood B sand.

Gascan submitted that the 15-10 well was also receiving pressure support from the 8-4 and 8-9 injectors. Gascan interpreted the 15-10 well as encountering the lower Gilwood B sand and said that the upper and lower zones were in communication in the area.

To support the premise of communication between the 15-10 well and the Unit injectors, Gascan stated that a pressure increase was experienced at 15-10, coupled with a significant drop in the producing GOR. However, Gascan admitted that the noted GOR performance might have been the result of solution gas migration away from the producing wellbore.

The applicant also noted that the productivity of the 15-10 well has increased as evidenced by the fact that no artificial lift was required to produce the well during a 7-day test in December 1983.

Gascan submitted that the acoustic well sounder (AWS) surveys in July 1982 and September 1983 demonstrated a significant pressure increase, and stated that the gradients used in the surveys, 6.00 kPa/m in 1982 and 7.962 kPa/m in 1983, were both calculated by the procedure outlined in ERCB Guide G-5. Using the reported gradients, Gascan calculated the 15-10 well pressure to be 16 814 kPa in 1982 and 18 903 kPa in 1983.

Gascan extracted pressure bomb data for a well in the Pool and found that the fluid gradient varied between 6.7 and 7.6 kPa/m. Gascan submitted that an increasing 15-10 well pressure was noted when the AWS gradients were adjusted based upon the latter gradient range.

Gascan concluded that the combination of pressure, GOR, and productivity evidence was conclusive proof that the 15-10 well was in communication with the Unit injectors.

5.2 Views of Chevron

Chevron submitted that pressure response at the applicant's 4-27 well had occurred due to the water injection at the 8-9 well. Considering the magnitude of the pressure response, the distance between the wells (5 km), and its experience in the Pool, Chevron described the degree of communication as "pretty good". Chevron drew a distinction between communication and effective communication and stated that although communication existed, there was no means available to Gascan to effectively control its proposed waterflood. Chevron also stated that there was some doubt that the proposed undrilled 14-4 injector would be in communication with the existing 8-9 and 4-27 wells.

Chevron stated that it was unsure as to the nature of communication between the 8-9 injector and the 15-10 well. It added that if the reservoir pressure at the 15-10 well had remained constant or declined over a period of time when the pressure increased at the 4-15 well, communication would be in doubt.

5.3 Views of the Board

The Board notes that the degree of communication between the proposed 14-4 injector, the existing injectors and the applicant's producing wells is yet to be determined but agrees with the applicant that, based on the current geological model, the proposed well should encounter the upper zone. The Board also agrees with both parties that above average communication exists between the 8-9 and 4-27 wells so that it is reasonable to expect, if the geological prognosis is correct, communication between the proposed injector and the 4-27 well.

As for the 15-10 well, the Board finds that the available performance data tends to support the existence of communication with the 8-9 injector. While the Board questions the absolute values of pressure in the 15-10 well, it concurs with Gascan's interpretation that the subject well has responded to the injection of water at the 8-9 well and therefore concludes that the lower zone in the 15-10 well is in pressure communication with the upper zone in the 8-9 well. As discussed in Appendix A to this report, a review of the available AWS data has indicated pressure levels in the 15-10 well that are too high for a well producing under primary depletion.

However, to extrapolate these conclusions to the proposed 14-4 injector is not presently justified in that interzonal communication in the reservoir is not a common phenomenon across the pool. Therefore, the Board believes it appropriate to exercise caution in authorizing the proposed schemes. In the event that the Board approves the proposed schemes, the applicant will be required to confirm from additional geological and pressure tests that the well drilled in 14-4 is in communication with the 8-9 well, and hence the 15-10 and 4-27 wells, prior to the implementation of the schemes. In addition, the applicant will be required to submit the results of an injectivity test on the 14-4 well.

6 THE ABILITY TO CONTROL THE PERFORMANCE OF WELLS IN THE SCHEMES

6.1 Views of Gascan

Gascan submitted that within a couple of months after injection began into the 8-9 well, the producing GOR at the 4-27 well began to decline, suggesting that the pressure transient due to the injection had propagated over the intervening land or a distance of 5.6 km. Pointing to a pressure increase of approximately 1000 kPa/year since June 1981 in the 4-27 well, Gascan concluded that the performance of the 4-27 well could be controlled by downdip injection at the 14-4 location.

Gascan stated that the producing GOR at the 4-27 well had decreased from approximately 2000 cubic metres per cubic metre (m^3/m^3) in 1981 to 80 m^3/m^3 in December 1983. The applicant further submitted that it could guarantee to the Board that a high GOR at 4-27 would not occur provided that the Unit replenishes its share of the total voidage.

Gascan noted that performance monitoring clauses are a usual requirement of a Board approval and if Gascan were unable to control the performance of its wells in 15-10 or 4-27, the performance clauses in the scheme approval would prevent any adverse impact on the surrounding area. Gascan concluded that it was prepared to accept the risk that failure to comply with performance clauses would result in removal of enhanced recovery status.

6.2 Views of Chevron

Chevron contended that Gascan would not be able to control the performance of the 4-27 well through downdip injection at either the 14-4 or 15-10 wells. Chevron stated that Gascan would not have the capability necessary to inject sufficient water volumes to repressure the 4-27 well without a corresponding detrimental impact on the Unit's operation. Chevron admitted that the Unit could offset any over injection by Gascan through reduction in its own injection volumes but stated that this would result in a decreased flexibility for the Unit to effect maximum recovery in its portion of the Pool.

Chevron acknowledged that no detrimental impact would occur to the Unit if Gascan failed to control the performance of its wells and was shut-in following violation of the Board's performance clauses. Chevron contended however that the schemes should be denied as Gascan could not control the performance of its wells.

6.3 Views of the Board

The Board is of the view that if the proposed 14-4 well encounters the Pool as predicted by Gascan, the applicant, in the absence of the Unit operations, would likely be able to pressure maintain the 15-10 and 4-27 wells through the downdip injection in the 14-4 location. In any case, if the Board approves the proposed schemes, Gascan will be required to satisfy performance clauses that are designed to prevent additional reservoir losses resulting from an inability to control its operations. If problems occur, the Board would rescind the enhanced recovery status granted the proposed scheme in any approval. Since the proposed schemes lack the usual flexibility to affect the producing wells by varying injection locations and because of the distance between the proposed injection well and the producing wells, there may be a higher than usual possibility of not satisfying the terms of an approval. It is clear that the inherent risk of this is Gascan's.

7 POSSIBLE ALTERNATIVE SCHEMES TO ENHANCE OIL RECOVERY IN THE REGION OF THE 4-27 WELL

7.1 Views of Gascan

Gascan submitted that its lands in section 27 were in communication with the lands in section 34, owned by Home Oil Ltd. (Home). It had examined and rejected updip injection due to the potential for additional oil losses between the advancing flood fronts, the proven effectiveness of the present Unit operated scheme to maintain pressure in the area, and the high risk of implementing an updip scheme.

Gascan stated that it had preliminary discussions with Home with regard to enhancing oil recovery in the Home lands through its proposed scheme. The applicant also said that it had not discussed with Home the possibility of an enhanced recovery scheme involving updip injection.

7.2 Views of Chevron

Chevron submitted that the applicant has the opportunity to implement its own scheme for oil recovery enhancement on its contiguous updip acreage. Chevron noted that Gascan had ownership of the north half of section 27 and suggested that a more suitable alternative to the proposed scheme would involve the drilling of an updip injector. Chevron stated that it would support an updip injection scheme that could possibly incorporate the Home wells in section 34. According to Chevron, the risk of drilling a successful updip injection well on the north half of section 27 was equivalent to the risk associated with drilling the 14-4 well.

7.3 Views of the Board

The Board believes that updip injection might be preferable were it not for the risks associated with the drilling of a successful injector in the area of the 4-27 well. The existence of two abandoned wells in the northwest quarter of section 27 leads the Board to assign a considerably greater risk to the success of drilling an updip injector. In addition, there was no evidence to indicate communication between the 4-27 well and the Home wells in section 34. Therefore, the Board concludes that the updip alternative proposed by Chevron represents a considerable risk and is not as attractive as the proposed scheme.

The Board concurs with the applicant that the proposed schemes are presently compatible with the existing enhanced recovery mechanism. However, inherent to the successful operation of a line drive waterflood is the transfer of injectors to the leading edge of the front as producing wells are watered out. In this manner, sufficient injectivity is maintained to balance withdrawals from the scheme. The Board recognizes that Gascan does not have this flexibility but believes a GOR and pressure clause in the approval would ensure balanced withdrawals from the scheme.

8 POSSIBLE PROLIFERATION OF SIMILAR SCHEMES AND THE POTENTIAL IMPACT ON POOL RECOVERY

8.1 Views of Gascan

Gascan submitted that unitization would be the most favourable solution to enhanced recovery operations in the Pool. Gascan realized that Unit enlargement was complex and stated that it had been attempting to gain entry into the Unit for 2 years.

Gascan submitted that it could no longer delay the implementation of its own scheme and doubted that Unit enlargement would occur. Gascan also stated that there would be no effect on Unit negotiations should its lands be granted enhanced recovery status due to the successful implementation of its schemes.

Gascan listed as the next preferable solution, a scheme for injection on behalf of itself by the Unit. Gascan stated that the Unit has refused to inject water on Gascan's behalf. Gascan perceived a scheme of this nature would provide the Unit with the opportunity to continue to manage its waterflood somewhat independently in the event that unitization is not possible.

Gascan admitted independent schemes like the two it proposed would be the least desirable since it duplicated injection facilities. Gascan stated that there would be no detrimental impact on Pool recovery as a result of its schemes, providing both it and the Unit maintain voidage replacement.

In summary, Gascan stated that each operator in a competing enhanced recovery scheme had an obligation to comply with its scheme approval and, assuming this to occur, no detrimental impact on Pool recovery would occur.

8.2 Views of Chevron

Chevron submitted that there were currently 29 other updip primary operators and that approval of the proposed schemes may lead to the proliferation of more schemes of a similar nature in the Pool. Chevron stated that schemes of this nature result in considerable economic waste through the duplication of injection facilities. In addition, Chevron suggested that the Unit may be forced into unnecessary expenditures to prevent drainage which may disrupt the efficiency of the waterflood. In summary, Chevron concluded that the proposed schemes and all similar schemes do not represent an economic, orderly, and efficient development of the Pool.

Chevron preferred unitization to the proposed scheme and stated that unitization would result in maximum oil conservation and efficient operation. Chevron submitted that unit enlargement was complex and was made more difficult by the lack of a unit enlargement method. Chevron also submitted that revised Unit participation factors had been calculated, they would be presented to the Unit's negotiating committee in early February 14 1984, and they would be available to the primary operators in March 1984. Chevron stated that the tract factors were calculated assuming enhanced recovery status for each tract and that no deadline had been set for the conclusion of unitization agreements. Chevron stated that approval of the proposed schemes would not alter the unitization timetable that it had presented.

8.3 Views of the Board

The Board agrees with both the applicant and Chevron that enlargement of the Unit to include all primary operators would be the most efficient solution in terms of economic expenditures and ensuring maximum oil recovery from the Pool. The Board recognizes that voluntary unitization is not always possible and, in the absence of compulsory unitization legislation, the Board is compelled to consider each application for oil recovery enhancement on its own merits.In this particular pool the Board finds it unfortunate that, with both parties agreeing on the benefits of unitization, an agreement has not yet been achieved.

The Board views schemes of this nature as an unfortunate but necessary choice in the absence of the more favourable alternative, unitization. The Board must consider the merits of any scheme as it arises and as it relates to oil recovery enhancement from the Pool. Thus the potential for the proliferation of such schemes remains an undesirable but inherent aspect of the existing situation.

The Board does recognize that approval of schemes such as those proposed by Gascan may force the Unit to limit off-Unit oil migration by drilling additional updip wells that are not presently required. Additionally, the Board recognizes that the flexibility of the Unit to enhance oil recovery on its lands may be somewhat limited. The Board believes however that in the absence of more favourable alternatives, the primary operators must have an opportunity to install enhanced oil recovery schemes provided they will operate in a satisfactory manner.

9 THE OPPORTUNITY OF EACH OWNER TO OBTAIN ITS SHARE OF PRODUCTION FROM THE POOL

9.1 Views of Gascan

Gascan said that it could recover more oil than the initial oil-in-place (IOIP) in its producing tracts. The applicant stated that some of its produced oil may drain from undrilled Unit lands but noted that the Unit can take measures to limit off-Unit oil migration through infill drilling.

Gascan submitted that laws defining equitable rights for owners in common pools are well established in Alberta. The applicant pointed to section 4(d) of the Act and concluded that each owner in a common pool was afforded the opportunity to obtain its share of the pool production, not its share of in-place reserves as implied by Chevron.

When the oil in the Pool moves from beneath one property to another property, Gascan submitted that the right and equitable opportunity to recovery of that oil rests with the owner of the lands under which the oil is then situated.

Gascan stated that by its application, it was now seeking the opportunity to obtain its share of the pool production.

9.2 Views of Chevron

Chevron described the proposed schemes as unusual in that the injection and production wells were separated by Unit lands thereby accelerating oil migration off Unit lands. Chevron strongly objected to approval of the schemes on this basis.

Chevron submitted that approval of the applicant's scheme would take oil from the Unit owners and give it to the applicant and stated that 99.9 per cent of the oil recovered from the 4-27 well over its remaining life would migrate directly from the Unit. Chevron referenced section 4(d) of the Act and submitted that granting the application would not permit the Unit owners to recover their share. Chevron questioned whether equities would be preserved if the schemes were approved by the Board. It acknowledged that it could limit the amount of off-Unit oil migration by drilling an offset producer to the applicant's 4-27 well.

9.3 Views of the Board

The Board agrees that the proposed schemes, if approved and later granted project status, would result in additional oil migration from Unit lands as a result of higher production allowables. However, most of the oil migration would result from the favourable position of the Gascan wells which affords the opportunity to capture oil pushed updip by the Unit injection scheme. The Board notes that the Unit has the opportunity both to obtain its fair share of Pool production and to limit off-Unit migration by infill drilling. In addition, the Board views the applicant's proposed schemes as not only benefitting ultimate oil recovery but as a means to afford the applicant an opportunity to produce its share of oil from the Pool.

10 BOARD CONCLUSIONS WITH RESPECT TO THE GASCAN APPLICATION

The Board has given due consideration to the submissions and evidence of the applicant and intervener and has reached the following conclusions:

- It would be premature to consider at this time the question of whether the proposed schemes would qualify for project status.
- The guaranteed replacement of reservoir voidage due to the production of primary wells is necessary to ensure maximum ultimate oil recovery from the Pool.
- The applicant's 15-10 and 4-27 wells are in communication with the Unit's 8-9 injector.
- If approved, recognition of enhanced recovery status for the schemes would be made dependent on the demonstration of communication between the 14-4 and 8-9 wells using geological and pressure data.
- Any alternative scheme of updip injection would represent considerable risk and therefore would not be as attractive as the proposed schemes.
- The proposed schemes will enhance oil recovery from the Pool, due in part, to the favourable structural position of the 4-27 well.
- The proposed schemes represent an attempt on the part of the applicant to obtain its equitable share of production from the Pool.

- The proposed schemes are desirable only in the absence of more favourable competitive schemes or Unit enlargement.
- Unit enlargement to include all primary lands would be desirable to ensure maximum and efficient recovery of oil from the Pool.

The Board therefore believes the schemes proposed by Gascan should be approved, subject to the appropriate performance conditions.

11 CONTROLS FOR PERFORMANCE MONITORING

11.1 Views of Gascan

Gascan proposed that its schemes should be required to maintain a voidage replacement ratio of at least unity. The applicant also suggested that its scheme should be subject to the same GOR restriction of 180 m^3/m^3 applied to Unit production. The applicant initially submitted that a voidage replacement and GOR peformance clause were sufficient to ensure that future recovery of oil from the Pool was protected. As a result of questioning, Gascan agreed that a maximum GOR restriction could be misleading due to the potential for gas migration and the associated shrinkage losses. As a result, Gascan indicated that inclusion of a minimum pressure clause in the approval would be appropriate provided that it would reflect the current bubble-point pressure of the reservoir fluid. The applicant suggested that this minimum pressure should not be set arbitrarily but could be best determined through discussions between it and the Board staff. Gascan further suggested that in the interests of the Pool as a whole, a minimum pressure clause should apply uniformly to all operators producing in the Pool.

11.2 Views of Chevron

Chevron submitted that, if approved, the proposed schemes should be required to maintain a voidage replacement ratio of one and also to adhere to a maximum GOR restriction of 180 m^3/m^3, and to a minimum pressure clause. Chevron submitted that the minimum pressure clause should reflect the reservoir fluid bubble-point pressure.

Chevron acknowledged that the Unit did not have a minimum pressure requirement in its approval for enhanced oil recovery, that some areas had experienced production curtailment due to the GOR limitation, and that gas migration had probably occurred. In those areas, Chevron agreed that a minimum pressure restriction would have been useful in performance monitoring.

11.3 Views of the Board

The Board believes that complete voidage replacement is essential to enhance oil recovery in the Pool. The Board perceives a need for both GOR and minimum pressure clauses to effectively monitor the performance of the proposed schemes. These clauses are required to prevent the rapid depletion of reservoir energy and the subsequent increase in shrinkage losses. The Board will establish the details of these clauses after further consideration of the technical aspects of the reservoirs.

The Board is aware that the Unit is not required to maintain a minimum pressure in its enhanced recovery approval. The Board recognizes that the Unit has flexibility to correct problems rapidly and that less rigid controls may be adequate. However, from evidence at this hearing, the Board is concerned that the performance requirements presently applied to the Unit scheme may not be sufficient to prevent unnecessary reservoir loss. To this end, the Board will, in the near future, request the Unit to examine the merit of a minimum pressure requirement on its scheme.

B THE CHEVRON APPLICATION

12 THE ISSUES

The Board believes the issues to be addressed in the Chevron application are:

- The performance of the existing waterflood in township 69, range 3, w5m, and the need for injection at an additional location.
- The degree of communication between the proposed injector and that portion of the reservoir intended to be swept, and the appropriateness of the well as an injector.

13 THE PERFORMANCE OF THE EXISTING WATERFLOOD AND THE NEED FOR INJECTION AT AN ADDITIONAL LOCATION

13.1 Views of Chevron

Chevron submitted that the lower sand in township 69, range 3, w5m, was not receiving sufficient pressure support from the Unit injection at the 8-4 and 8-9 wells. Chevron stated that GORs were generally high in the wells in the eastern half of the township and that successful recompletions in the 10-15 and 13-15 wells determined that the lower zone was the source of gas. Therefore, Chevron concluded that additional sources of injection into the lower zone are required for effective pressure maintenance.

Chevron referred to its application as a first step in providing the required injection into the lower zone. In addition to the proposed 2-22 injector, Chevron plans to drill a well in section 11 and, with the additional information gained, to choose an additional injector in that area.

13.2 Views of Gascan

Gascan submitted that the current Unit waterflood scheme was adequately pressure maintaining the upper zone channel with wells in sections 10, 15, 16, 21, 27, and 29. Gascan concurred with the applicant that the wells east of the channel with pay in the lower zone were not receiving sufficient pressure support and were producing high GORs. Gascan identified the wells in sections 1, 2, 12, 14, 22, and 23 as requiring additional pressure support.

13.3 Views of the Board

The Board agrees with both parties that the wells east of the high permeability upper zone channel are in need of additional pressure support as evidenced by the high GORs in the area. The Board also agrees with Chevron's conclusion that the lower zone is the source of high GORs based on the results of the 10-15 and 13-15 recompletions. Therefore, the Board concludes that additional injection into the lower zone is required to prevent a loss in recovery from that zone.

14 COMMUNICATION BETWEEN THE PROPOSED INJECTOR AND THE RESERVOIR AND THE APPROPRIATENESS OF THE WELL AS AN INJECTOR

14.1 Views of the Applicant

Chevron stated that the proposed 2-22 injector was intended to provide pressure support in both the upper and lower zones in sections 14, 15, and 16, and would result in increased recovery of some 97 000 m^3 of oil. Chevron evaluated the 15-16 well as a potential injector but rejected it as no incremental oil recovery was predicted from its use.

The applicant submitted that both the upper and lower sand zones were perforated and in communication at the 2-22 well and that the well would contribute to pressure maintenance of the upper zone. This interpretation was based on geological models rather than pressure data as the 2-22 well has not been pressure surveyed since 1981.

Chevron stated that even though injection at 2-22 would result in an updip flood, oil entrapment would be minimized, as the 2-22 well is situated near the updip oil reservoir edge. Also, the well is surrounded by downdip producing wells, and there are producers between the 2-22 well and the existing waterflood front. Chevron also stated that according to its model studies, the Gascan 4-27 well would not be flooded by the 2-22 well for at least 10 years.

Chevron recognized that the area surrounding section 11 also required additional injection and said it would be drilling a well in section 11, thus providing additional geological information to select the appropriate injection location. Chevron submitted that the approval of injection at 2-22 would not affect the future injection needs in the section 11 area.

14.2 Views of Gascan

Gascan submitted that Chevron had not included the necessary information in its application to enable Gascan to fully analyse the effect of the proposed injector on Gascan's properties and requested the Board either deny or defer approval of the application until the relevant model data was made available.

In addition, Gascan submitted that all but two of the wells targeted by Chevron to receive pressure support from the 2-22 well were already receiving pressure support from the current injection. Gascan questioned the need for introducing an updip injector in this area.However, Gascan concurred with the applicant that the lower zone wells, east of the upper zone channel, were not receiving pressure support. Gascan agreed that additional injectors were necessary in that area but suggested that it would be premature to approve injection at the 2-22 well while Chevron evaluated the area surrounding section 11. Gascan submitted that the wells in the lower zone should be studied and the additional injectors should be chosen from that study.

14.3 Views of the Board

The Board agrees with both parties that additional injection is necessary to maintain pressure in the lower Gilwood B sand, but is not convinced that the upper and lower zones are in communication in the vicinity of the proposed 2-22 injector. The Board believes the degree of continuity between the 2-22 well and the highly permeable upper zone channel is not substantial so that injection into the lower zone will prevent additional oil losses and will satisfy the pressure maintenance requirement in the area.

The Board agrees with Chevron that oil trapping due to updip injection will be minimized and believes that oil trapping between the advancing waterflood fronts can be eliminated by balancing production in the intervening wells. The Board recognizes that the reservoir surrounding section 11 also requires additional pressure maintenance and that Chevron is studying the area to determine the appropriate injection location. The Board agrees with Chevron's position that injection at the 2-22 well will not impact on its future plans for the section 11 area.

The Board concludes that additional injection is required to pressure maintain the lower Gilwood B zone and that the proposed 2-22 injector will satisfy that need in sections 10, 14, 15, and 16. Also, injection at the 2-22 well will incur a minimal oil trapping loss.

15 BOARD CONCLUSIONS WITH RESPECT TO THE CHEVRON APPLICATION

The Board has given due consideration to the evidence respecting the application and concludes:

- Additional injection is required to pressure maintain the lower Gilwood B sand.
- The proposed 2-22 injector is completed in the lower zone.
- Injection at the 2-22 well will benefit recovery from the lower zone in sections 10, 14, 15, and 16.
- There is minimal potential for oil trapping due to injection at the 2-22 well.

16 DECISION

The Board approves Application 830996 by Gascan Resources Ltd. for two enhanced recovery schemes in the Mitsue Gilwood A Pool. The appropriate performance conditions will be made part of the Board approval.

The Board approves Application 831212 by Chevron Canada Resources Limited for an amendment of its enhanced recovery approval for the same pool.

The necessary approval and amendment to Approval 3665 will be issued in the near future.

DATED at Calgary, Alberta, on 17 April 1984

ENERGY RESOURCES CONSERVATION BOARD

GJDeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

APPENDIX A: DETERMINATION OF FLUID GRADIENTS FOR THE AWS SURVEYS ON THE 15-10 WELL

The pressures as submitted by Gascan were estimated from acoustic well sounder (AWS) surveys on the 15-10 well using gradients that varied from 6.00 kPa/m in 1982 to 7.96 kPa/m in 1983. Based on the referenced gradients, the pressure over the period in question had increased from 16 471 kPa to 18 812 kPa in 1983. However, the latter pressure and as a consequence the noted pressure response, is open to question in that it exceeded the injection pressure at the nearby 8-9 well. As the noted pressure increase is credited to the change in fluid gradients, the Board finds it necessary to examine the factors that make up or contribute to the fluid gradients.

In addition to the reservoir temperature and oil density, which are expected to remain relatively constant throughout the depletion history of the well, the producing characteristics and gas-liquid contact pressure in the annulus would contribute heavily to changes in fluid gradient. As for the producing characteristics, the available performance data for the period in question suggest that the 15-10 well continued to produce water-free oil with insignificant changes in the producing gas-oil ratios. However, the referenced AWS tests have shown a considerable drop in the gas-liquid contact pressure from 13 710 kPa in 1982 to 8145 kPa in 1983, indicating that a higher gradient in the latter test would be in order

The results, analysed using the recommended procedures in the Board's Guide G-5, suggest fluid gradients of 6.33 and 6.89 kPa/m, yielding pressures of 16 821 and 17 470 kPa in 1982 and 1983, respectively When compared to their counterparts in the 4-15 well, which is located on the high permeability channel in the area, the latter pressures suggest communication with the nearby 8-9 injector.

The Board recognizes that the Guide G-5, which is intended to cater to a wide variety of pools, may not provide a reliable estimate of gradients in some instances. Therefore, as an alternative, the Board reviewed the available gradient data from nearby wells where pressures have been determined with bottom-hole pressure gauges. This review indicated that a gradient of about 5.6 kPa/m in 1982 and 6.1 kPa/m in 1983 would be reasonable approximations. Based on the latter gradients, the resulting pressures in the area of the 15-10 well would be close to 16 450 kPa in 1982 and 16 400 kPa in 1983. The latter pressure is high considering the fact that the 15-10 well has produced nearly 7 per cent of its oil in place. The above review and the consistency of the pressures in the 4-15 and 10-15 wells support the conclusion that the latter well is receiving pressure support from the 8-9 injector.

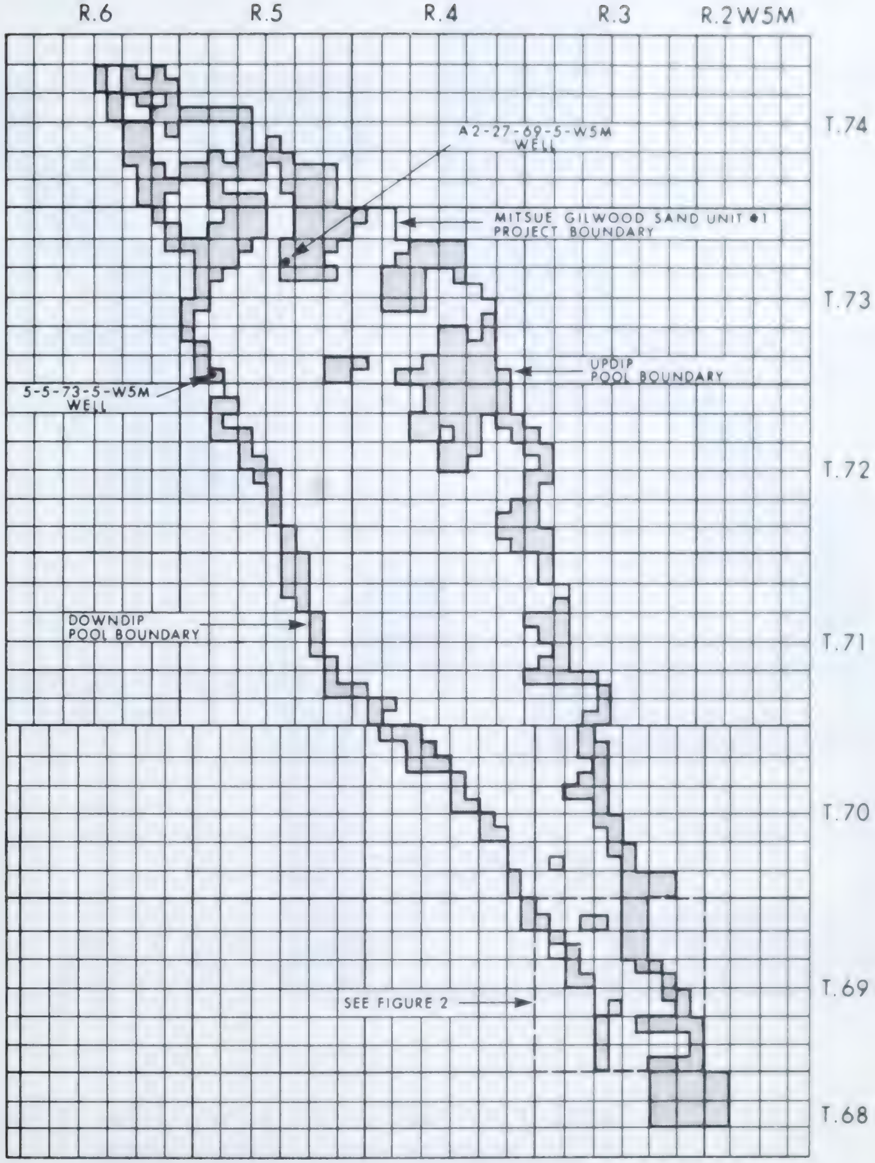

FIGURE 1 THE MITSUE GILWOOD A POOL

▨ PRIMARY AREA

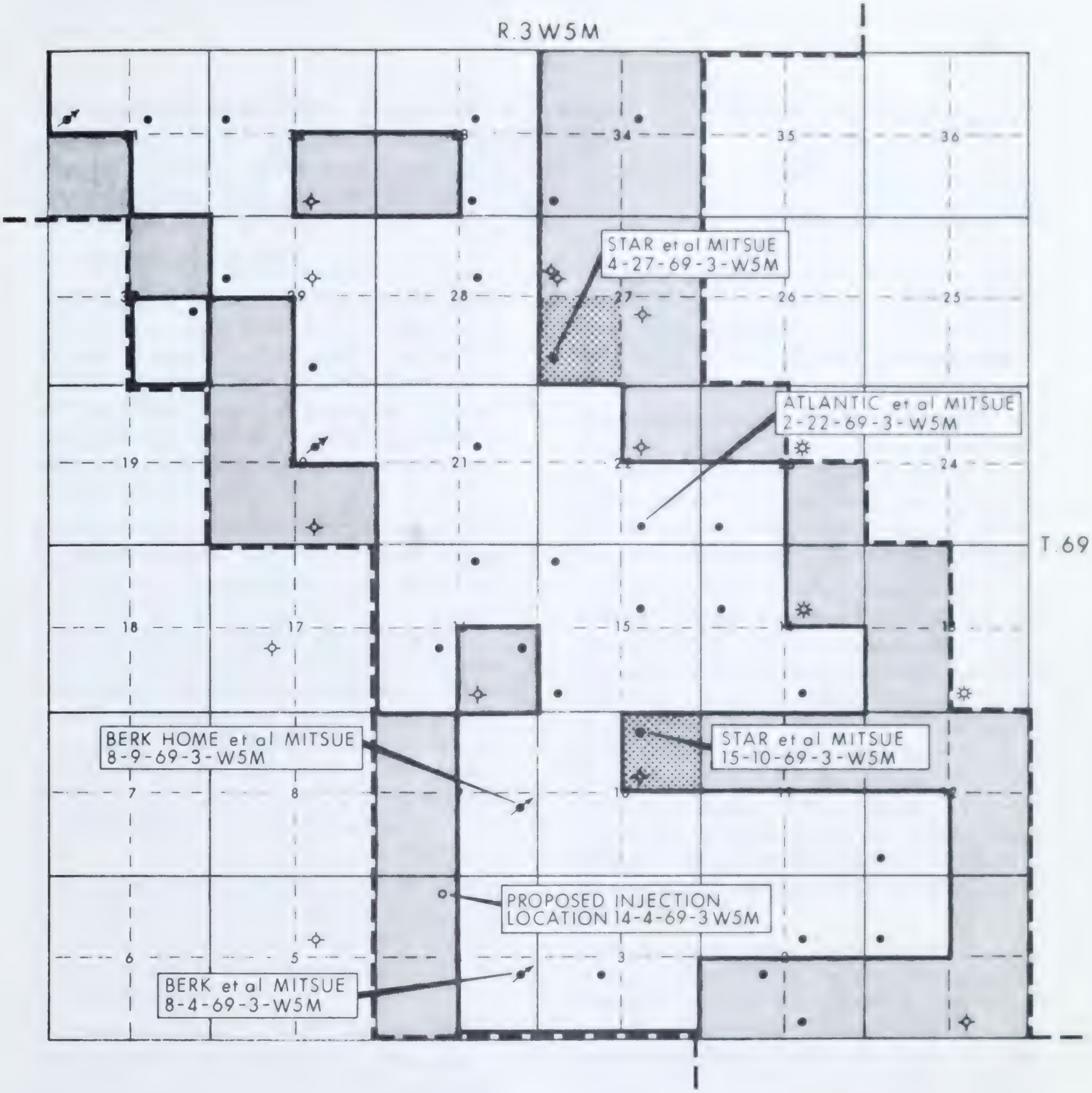

FIGURE 2 WELL LOCATION IN TWP. 69-3-W5M
(FROM APPLICATION 830996)

ø INJECTION WELL

● OIL WELL

⌖ DRY & ABANDONED

☼ GAS WELL

— MITSUE GILWOOD SAND UNIT #1 PROJECT BOUNDARY

– – POOL BOUNDARY

☐ PRIMARY AREA

▨ PROPOSED SCHEME AREAS

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

LODGEPOLE BLOWOUT INQUIRY — PHASE 2. SOUR GAS WELL BLOWOUTS IN ALBERTA; THEIR CAUSES, AND ACTIONS REQUIRED TO MINIMIZE THEIR FUTURE OCCURRENCE

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Decision D 84-5
Proceeding 830007

1 EXECUTIVE SUMMARY

The inquiry into the Lodgepole blowout[1] was undertaken in two phases; Phase 1 being an inquiry into the causes and impacts of the blowout of the AMOCO DOME BRAZEAU RIVER 13-12-48-12 well (13-12 well), and Phase 2 being an inquiry into improvements that might be made in drilling operations in order to reduce the possibility of another such blowout occurring in Alberta.

Several important recommendations were made during the second phase of the inquiry and the Inquiry Panel (Panel) is convinced that while the Alberta blowout record is comparable to that in other jurisdictions, it can be improved. Furthermore, because drilling is on-going, the Panel believes that improvements should be instituted as quickly as possible to reduce immediately the potential for another "Lodgepole". It has, therefore, decided to complete and publish its report on the second phase of the inquiry prior to the completion of its report on the causes and impacts of the blowout of the 13-12 well.

Participation in Phase 2 of the inquiry included representatives from oil and gas industry associations, and several major companies. There was also limited participation from the general public and the Alberta government.

The Panel has reviewed all of the recommendations made and believes that many of them can assist in reducing the number of blowouts in Alberta, particularly blowouts of sour gas wells. While some of the recommendations can only be implemented after research and review, several can be initiated immediately and the Panel has so recommended.

Almost everyone appearing at the second phase of the inquiry agreed that the primary cause of blowouts is human error and the remedy is to reduce that possibility. Immediate steps should be taken, therefore, to improve and increase training and awareness of the potential contributory factors by *all persons* associated with drilling operations. The blowout prevention process must begin with the initial plans for drilling the well and must include the equipment to be used and the special precautions to be taken. All parties must support an improved and comprehensive inspection process to ensure that the equipment, planning, and its execution are fully effective.

The Panel has asked the ERCB to implement, as a priority, a program which will impose additional controls in the planning for and drilling of certain critical sour wells. For such wells, the drilling plan and equipment to be used will require ERCB approval. An emergency response plan will also be required.

A review committee will also be formed to identify measures to improve training and awareness with respect to drilling and to improve the planning for, and equipment used in drilling into formations where high pressure hydrogen sulphide (H_2S) gas may be encountered. Human error as a factor in drilling operations will be reviewed to determine what actions to reduce it are feasible. The inspection of drilling rigs will be addressed by the committee with a view to increased inspections prior to critical drilling operations, and the potential for the development of an Alberta code of practice for drilling will be examined.

Some activities are already underway and others will be implemented following the release of this report. Time limits for reporting to the ERCB by the review committee have been set to ensure that results are obtained respecting the improvements required. These findings and others are more specifically described in Section 6 of the report.

The Panel expects that implementing the recommendations arising out of Phase 2 of the Lodgepole Inquiry will lead to improved oil and gas well drilling practices in Alberta which will reduce the number of well blowouts, especially sour well blowouts.

2 INTRODUCTION

2.1 Background

The well, AMOCO DOME BRAZEAU RIVER 13-12-48-12, located in legal subdivision 13 of section 12, township 48, range 12, west of the 5th meridian, near the hamlet of Lodgepole, Alberta, blew out of control from 17 October 1982 to 23 December 1982 — a total of 67 days. On 14 January

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[1] A glossary of oilfield terms is attached as Appendix 1.

1983, the Energy Resources Conservation Board (ERCB) announced that an inquiry would be held ". . . to determine the facts surrounding the Lodgepole gas well blowout . . .". Three pre-inquiry meetings were held to establish terms of reference and other details of how the inquiry should proceed. The terms of reference were issued on 5 May 1983. The inquiry was separated into two phases — the first to deal specifically with the blowout of the 13-12 well and the second

> ". . . to inquire into, report upon, and make such recommendations as are necessary or advisable in relation to the causative factors of sour gas blowouts in Alberta and actions that can be reasonably taken to minimize the possibility of future occurrences."

This report pertains to Phase 2 of the inquiry.

2.2 Procedural Decisions

The inquiry was separated into two phases in order to facilitate industry participation in that portion of the inquiry dealing with the broad question of blowouts in the Province as a whole. For the same reason, the Panel agreed to move the venue for Phase 2 from Drayton Valley to Calgary. It was also decided to conduct separate registrations of participants for Phase 1 and Phase 2, to hold separate final arguments, and to issue separate reports. The Panel also decided there would be one continuous record for both phases of the inquiry and as a result, evidence filed and heard in Phase 1 would, where appropriate, apply to Phase 2, and vice versa.

2.3 The Inquiry

The Panel consisted of V. Millard, Inquiry Panel Chairman, and Panel Members, G. J. DeSorcy, P.Eng., F. A. Herbert, M.D., J. W. Markham, M.B., N. A. Strom, P.Eng., and R. S. Weaver, Ph.D. Participants in the inquiry are listed in Appendix 2.

Phase 1 of the inquiry was held from 1 November 1983 to 15 February 1984 in the town of Drayton Valley, Alberta, except for one day in Edmonton, Alberta, on 9 December 1984. Phase 2 was held from 20 February 1984 to 2 March 1984 in Calgary, Alberta.

2.4 Sour Gas Wells in Alberta

Early in 1983, the Panel commissioned F. G. Bercha and Associates Limited to analyse the risk of sour gas drilling blowouts in Alberta. Bercha found that the number of sour gas wells drilled in Alberta was too low to permit meaningful statistical study as a separate group. Bercha found that approximately 1 per cent of the 20 000 wells drilled in the three years 1980 to 1982 were sour. In separate evidence, the ERCB staff testified that of the 220 sour wells drilled in 1980-1982, 160 were classified as sour oil wells and 60 as sour gas wells. Of the 60 sour gas wells only 25 produce gas containing more than 1 per cent H_2S.

Bercha found it necessary to analyse the data for all wells, whether sweet or sour, oil or gas, and then modify its findings to reflect the frequency of occurrence of H_2S. Bercha made no distinction between oil and gas wells.

3 WELL BLOWOUTS IN ALBERTA

3.1 Risk of Blowouts

Blowouts occur as a result of a failure to control a "kick". Based on a review of the ERCB's computer records and document files, Bercha found that of the 4000 to 6000 wells drilled each year in Alberta

- 1 in every 29 (3.5×10^{-2}) would experience one or more kicks,
- 1 in every 2900 (3.5×10^{-4}) would experience a blowout, and
- 1 in every 62 500 (1.6×10^{-5}) would be a sour gas well blowout.

The above estimate of the sour gas well blowout rate is based on the proportion of sour wells in the total number of wells drilled and the assumption that sour wells are no more difficult to drill than sweet wells. However, the Panel has reviewed the ERCB data and found that 6 sour gas well blowouts were experienced while drilling 51 000 wells from 1974 to 1983. This is 1 in every 8500 (1.2×10^{-4}). The total number of sour gas wells drilled was 1030; therefore, the rate of sour gas well blowouts per sour gas wells drilled is 1 in every 172 (5.8×10^{-3}).

Bercha testified that the higher blowout rate actually experienced for sour gas wells is the result of a number of factors:

- sour gas is highly corrosive and equipment failures are more likely in the presence of sour gas,
- in any potentially sour environment, blowout prevention procedures are complicated by the need for drilling crews to take greater precautions, and
- deeper wells, whether sweet or sour, experience a much greater rate of drilling problems, and sour gas is found only in the deeper formations.

From the ERCB's records of the wells drilled in the period 1980-82, Bercha was able to relate the occurrence of a kick (ie, the first stage of a potential blowout) to the drilling operation in progress. He found that the 703 kicks reported occurred

40 per cent while tripping out,
33 per cent while drilling,
13 per cent while circulating,

7 per cent while tripping in,
3 per cent while coring,
2 per cent while testing, and
2 per cent while other operations were in progress.

A brief description of the blowouts in the last 10 years is provided in Appendix 3.

A review of the circumstances leading to these blowouts reveals that they occurred

43 per cent while tripping out,
33 per cent while drilling,
10 per cent while running casing,
5 per cent while circulating,
5 per cent while logging, and
5 per cent while coring.

These findings are very similar to those reported by Bercha, even though they are for blowouts rather than kicks, are for a different time period, and are for a much smaller number of occurrences.

3.2 Cost of Blowouts

Confer Consulting Ltd. was engaged by the Panel to develop estimates of the costs associated with blowouts for a range of consequences identified as minor, moderate, and severe. These were to reflect the consequences defined as sour gas well blowouts lasting 1 day, 6 days, and 100 days, respectively. Equipment losses and other consequences were assumed to escalate progressively with the duration of the blowout.

Confer estimated that the cost of a severe sour gas well blowout could be 50 million dollars, of which one half would be the cost of lost, delayed, or deteriorated hydrocarbon production. A moderate blowout could cost 2 million dollars, of which 0.5 million dollars was associated with hydrocarbon losses. A minor blowout could cost less than 200 thousand dollars with negligible hydrocarbon losses.

It should be noted that these costs do not include many intangible and unquantifiable social costs such as nuisance impacts and the feelings of anxiety on the part of the general public.

With potential costs of the magnitude estimated above, the Panel believes certain measures to reduce blowouts are justified, particularly for sori wells where the impacts would be greatest. For instance, the Panel believes it would be beneficial for industry to direct funds into research concerning equipment and materials on a continuous basis and to support efforts to reduce blowouts.

3.3 Alberta Drilling Performance

3.3.1 Blowout History

The frequency of well blowouts in Alberta for the past 25 years is presented in Figures 1 and 2. Figure 1 shows the number of wells drilled and the number of blowouts. Figure 2 shows a 3-year moving average of the number of blowouts per well drilled. It reveals a low in the number of blowouts per well drilled in 1963, a rapid rise to a peak in 1969, followed by a decline to the present time. No evidence was heard to explain the marked variation in the blowout rate in the 1960s, however, the Panel is aware that the Pembina-Cardium area was drilled in the late 1950s and early 1960s, and it is a low permeability sweet oil pool which would not likely result in blowouts. In contrast, the Zama-Keg River area of northwest Alberta was drilled in the late 1960s, and it is an area prone to lost circulation and other drilling problems.

The blowout rate dropped substantially in the early 1970s and has further declined in recent years to one blowout for every 2900 wells drilled (a rate of 3.5×10^{-4}). Several participants credited the decline to improved equipment and improved training of rig personnel. CAODC noted that the first complete blowout prevention course designed by industry was presented in 1968. In 1971, well control training facilities were established at Golden Spike.

3.3.2 Comparison to Other Jurisdictions

Many of the witnesses who appeared in Phase 2 had drilling experience in other parts of the world — either in other provincial or federal jurisdictions within Canada or in other countries. Although they provided no details, the majority of witnesses examined on this subject said they believed Alberta's blowout record was comparable to that in other jurisdictions.

Bercha testified that, on the basis of other blowout studies it had done and the literature it had reviewed, Alberta's recent blowout rate of 3.5×10^{-4} was remarkably close to the estimated world average of 3.9×10^{-4} for land-based wells.

3.3.3 Rig Inspections

Drilling equipment is inspected separately and regularly by operators, contractors, and ERCB staff. Current regulations do not require operators or contractors to file their inspection reports with the ERCB. The matter of rig inspections is dealt with further in Appendix 4.

ERCB staff testified that inspections of drilling rigs had been carried out by its staff on 33 per cent of all wells drilled during the years 1979 to 1983. The staff found that 47 per cent of the rigs inspected were unsatisfactory in some respect. Of the 47 per cent found unsatisfactory, 83 per cent had one or more serious deficiencies. A serious deficiency was

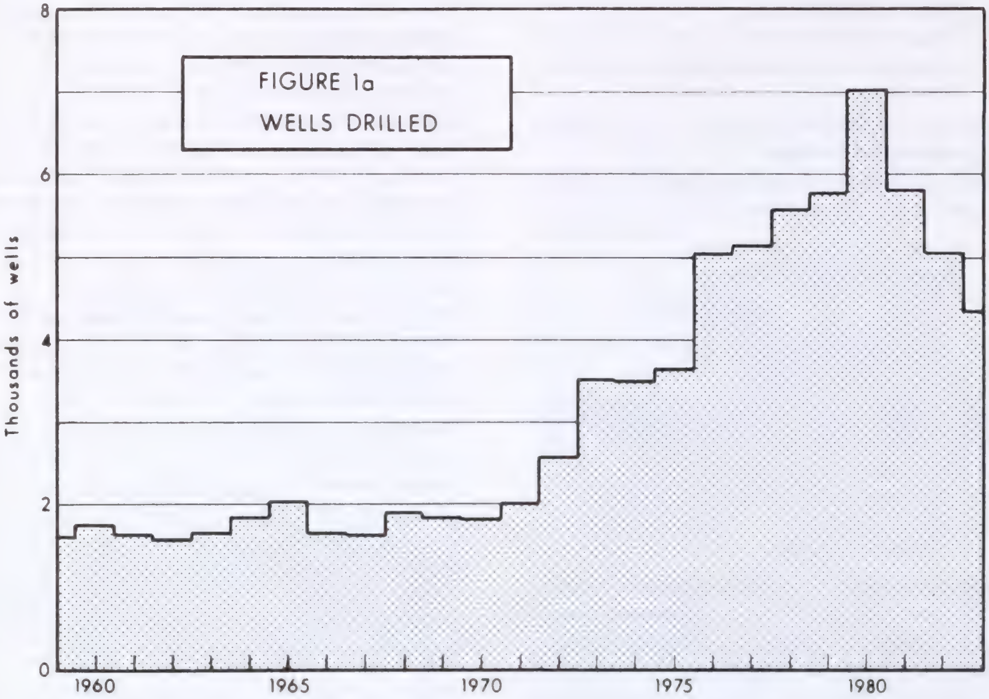

FIGURE 1a

WELLS DRILLED

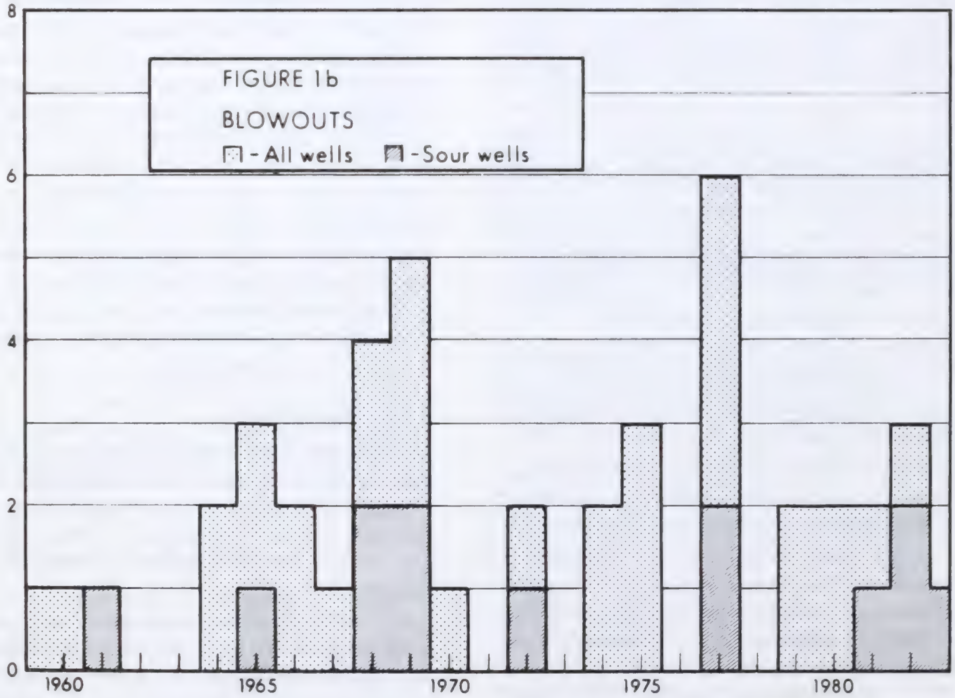

FIGURE 1b

BLOWOUTS

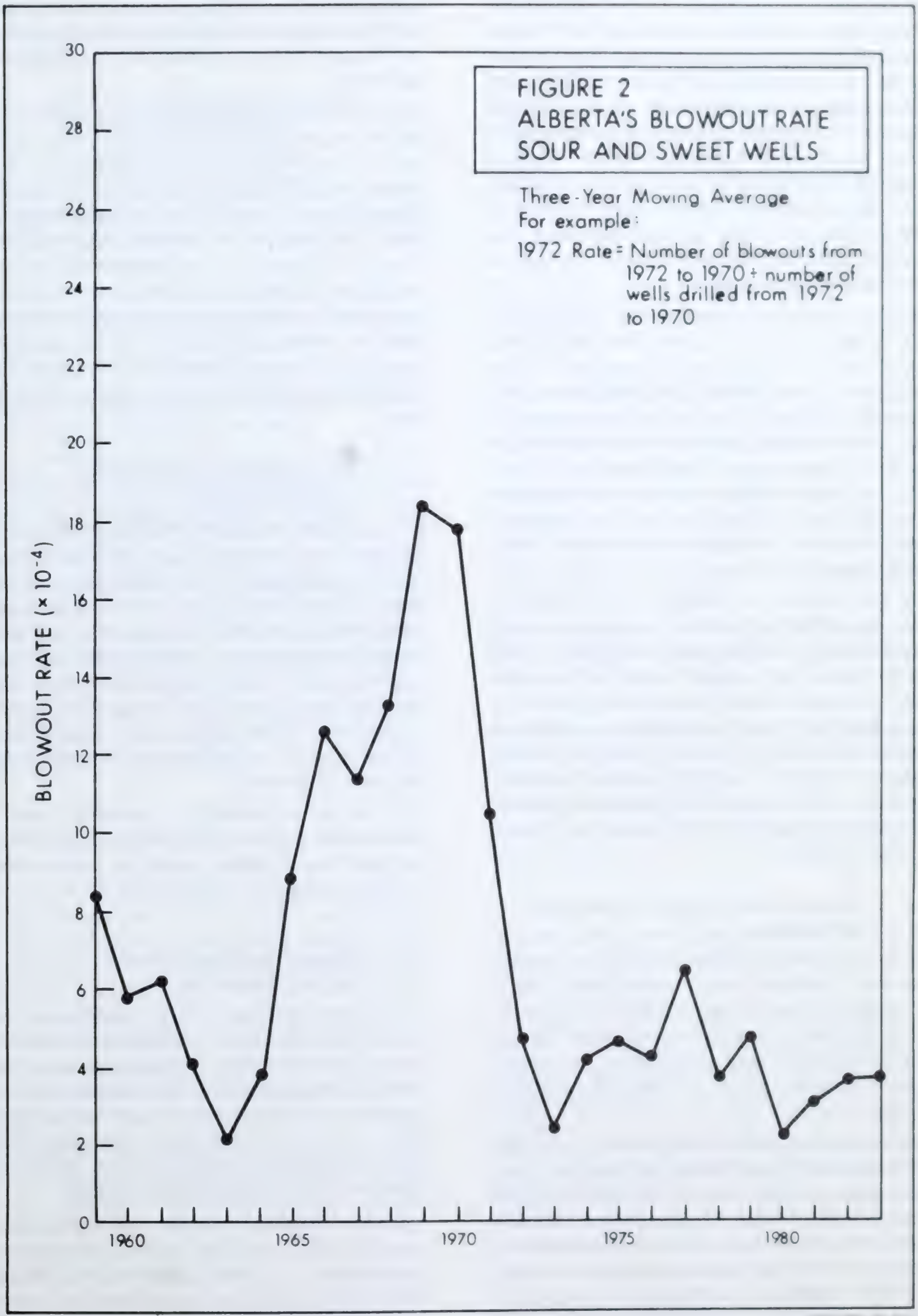

FIGURE 2
ALBERTA'S BLOWOUT RATE
SOUR AND SWEET WELLS

Three - Year Moving Average
For example:
1972 Rate = Number of blowouts from 1972 to 1970 ÷ number of wells drilled from 1972 to 1970

described as a matter that might hinder well control under certain circumstances. One of the circumstances that would have to exist in order for the serious deficiency to represent an immediate danger is that the rig would have to be drilling in or approaching a porous formation where a flow of fluid into the wellbore would be possible. Indeed, only 4 per cent of the rigs found unsatisfactory were judged to be in immediate danger to the extent that they were immediately shut down and further drilling progress prohibited until the deficiency was rectified. A further 16 per cent required immediate correction but were not shut down.

Serious concern was expressed as to whether the ERCB staff definition of serious deficiencies was appropriate. The ERCB staff emphasized that the definitions had been developed to direct its available inspection staff to new rigs, rigs with poorer records, and those in trouble prone areas, and not for the purpose of measuring the overall adequacy of rigs. The staff suggested that it and industry representatives should review the definitions and inspection data and prepare a new set of statistics which would reflect overall rig adequacy.

The Panel agrees this should be done and has so recommended to the ERCB. A committee is being appointed by it, including a representative on behalf of the public, and a report, which will be made public, is expected within two months. The committee is being asked to review the adequacy of inspection coverage, not only by the ERCB but also by industry, and to recommend ways in which the inspections and resulting reports could be better co-ordinated. The letter inviting participation on the committee is attached as Appendix 4.

3.4 Scope for Improvement in Incidence of Blowouts

Figure 2 illustrates that there has been a wide variation in well blowout rates over the last 25 years. Although most participants stated they believed an irreducible minimum existed because the basic problem is human error, none suggested that the low rate experienced in the last few years could not be reduced further.

Bercha concluded that all blowouts were the result of the failure to control a kick, and that failure was most often the result of human error. Several of the other participants agreed that human error was often involved, but many believed that a combination of human errors and other factors (eg, equipment failure, weather conditions, unpredictable geological conditions) played a combined role in causing blowouts. Bercha concluded that the greatest potential for reducing the blowout rate was by increased enforcement of the drilling regulations, followed by improved training of drilling personnel. While some participants agreed with Bercha, the majority stated they believed improved training would be the most beneficial.

The Panel concludes that the frequency of blowouts can be reduced further and in view of the much higher blowout rate for sour wells, believes that emphasis should be placed on that category. However, because of the human factor it is unreasonable to expect elimination of all blowouts. Improving the training of all persons involved with the drilling operation will most likely reduce blowouts and adjustments must be made to other factors that contribute. Since the potential for blowouts will always exist, industry will have to maintain its vigilance. The Panel will be be addressing these matters later in the report.

4 RECOMMENDATIONS BY PARTICIPANTS

4.1 Primary and Secondary Recommendations

The participants presented many recommendations and there was considerable agreement on most of these. The Panel has classified some of these recommendations as "primary" because they deal with matters of major importance which should be addressed as soon as possible. Other recommendations of less immediate importance have been classified as "secondary". These relate to matters which generally would not be critical in terms of reducing the likelihood of blowouts.

The Panel has also identified a number of "other" recommendations that are beyond the terms of reference for Phase 2 of this inquiry, or may require action by agencies other than the ERCB.

4.2 Recommendation to Form a Review Committee

A recommendation that received wide support was that a joint ERCB/industry blowout prevention review committee be established. Participants stated that many of the matters dealt with required detailed technical and economic review, and that for others there was a lack of information available. They recommended that these be referred to the review committee for detailed assessment or study.

The Panel agrees that there is a need for a review committee. The committee should be made up of representatives of CAODC, IPAC, CPA, and the ERCB and representatives of the public and certain Government departments should be invited to participate on selected sub-committees of particular interest to them.

In subsequent sections of this report the Panel will identify those matters that the review committee should examine, indicating the urgency or time constraints.

5 PANEL VIEWS ON SPECIFIC RECOMMENDATIONS

5.1 Primary Recommendations

5.1.1 Critical Sour Well Definition

Participants in the inquiry generally agreed with the establishment of a category of "critical sour wells" that would recognize:

(a) the location of the well,
(b) the estimated maximum H_2S concentration, and
(c) the estimated maximum flow rate.

Special precautions and blowout prevention controls would then be practised at these wells.

The Panel agrees that there is considerable merit in defining and imposing special controls on critical sour wells. It also saw considerable urgency in this respect and consequently recommended that the ERCB take immediate action. A draft Interim Directive defining critical sour wells and setting special requirements for them is being issued simultaneously with this report and is attached as Appendix 5. It will be used on an interim basis for approximately six months. The review committee and representatives of public interest groups and Government departments will be asked to review and comment on it. A revised long-term policy will then be instituted.

5.1.2 Training

Almost all participants suggested increased attention to the training of rig crews, including more hands-on training during blowout prevention drills, with particular focus on training for the driller and those rig workers that report to him. Suggestions included certification of both the drilling foreman and rig manager, establishment of a third line blowout prevention certificate, specific training for the driller and the rig workers he supervises (derrickman, motorman, and roughnecks), an H_2S awareness course for crews, and an increase in management awareness of drilling practices and the consequences of failure.

The Panel believes that human factors are very significant in terms of preventing blowouts. For this reason, increased training could be a significant and effective factor in reducing blowouts and the Panel agrees with the participants that it should be pursued. In addition to the increased training in the conventional sense, eg, blowout drills, the Panel believes that an analysis should be made of how human errors cause blowouts, and what preventative action might be taken.

The Panel suggests that the matter of training should be a priority item and should be handled within six months of the formation of the review committee. A further analysis of human factors which cause blowouts should be pursued by the committee, or perhaps a sub-committee, over the longer term. Factors such as education and experience, age, health, safety attitudes, hours of work, turnover rates, fatigue, and boredom are examples which would be included in the terms of reference of the committee. An opportunity to comment on the recommendations of the committee should be given to Government departments such as Labour, Manpower, and the Workers' Compensation Board, to the public, and representatives of training services.

5.1.3 Increased Enforcement

The participants at the inquiry were divided with respect to increased enforcement of regulatory controls. One suggestion involved the suspension of the crew members' blowout prevention (BOP) certificates and shutting down well operations for infractions at well sites. Participants encouraged the ERCB and operators to ensure that blowout prevention drills were done properly and recorded.

The Panel agrees and has asked the ERCB to increase enforcement, particularly on critical sour wells and with respect to blowout prevention drills. Care should be taken in distinguishing between minor and serious infractions and the latter should result in suspension of rig operations until corrective action is taken. The Panel recommends that the review committee, with input from appropriate Government departments, consider the factors involved in the suspension of BOP certificates.

5.1.4 Inspection

The participants were supportive of increased ERCB and operator rig inspections, particularly with respect to critical sour wells at critical times during drilling.

The Panel agrees there is a need for increased inspection of wells drilling into abnormal pressure and high H_2S concentration formations and believes that inspection should take place prior to drilling critical portions of the well. The draft Interim Directive, Appendix 5, sets this out as a particular requirement for critical sour wells. The Panel is aware that the ERCB is analysing its rig inspection policy with respect to arrangements for rigorous and more frequent inspections of wells that may encounter sour gas.

5.1.5 Supervision

A strengthening in the number and experience of the on-site supervisory personnel by operator and contractor at wells drilling into sour formations was suggested by several participants. Specific suggestions included a special team for high pressure H_2S wells, a minimum 5-man crew on all sour wells, supervisors on 12-hour shifts for critical wells at critical times, and increased training for operator and contractor representatives.

The Panel agrees that supervision should be enhanced for drilling critical sour wells with particular attention to the critical drilling periods. The draft Interim Directive requires, for critical sour wells, a minimum 5-man crew, experienced supervisors on maximum 12-hour shifts, and additional specialized safety personnel on site at all critical drilling periods.

5.1.6 Special Drilling Equipment

Unanimous support was given for the formation of an ERCB/industry committee to review a multitude of equipment-related concerns with particular emphasis on equipment for sour gas drilling. The most important of these items were the improvement of drilling monitors and kick detection equipment, degassers, shear rams, inside BOPs, drill pipe, the need for H_2S-resistant equipment, and the location of the lower drilling spool.

The Panel is in agreement that the review committee should consider drilling equipment with emphasis on high pressure H_2S requirements. It believes the committee should bring forth recommendations as they are formulated and that the most important items should be dealt with in 6 to 12 months.

5.1.7 Information Exchange

The publication of the causes and circumstances of blowouts, drilling rig deficiencies found by ERCB inspections, and the gathering of drilling data from world-wide sources into a central location were suggested and generally supported by the participants.

The Panel agrees with the suggestions but notes that prior to the publication of drilling rig deficiencies, analysis and evaluation is required to ensure the data is meaningful. The Panel understands that the ERCB will, where possible, publish a report outlining the cause and circumstance of blowouts in Alberta. Appendix 3 is intended to assist in this regard. The Panel will recommend that the review committee establish a format for the gathering of drilling and other relevant data with particular emphasis related to drilling high pressure H_2S formations.

5.1.8 Site-Specific Emergency Response Plans

Some participants suggested that there should be site-specific emergency response plans for the drilling of critical sour hydrocarbon wells.

The Panel considers it essential for site-specific emergency response plans to be in place prior to the drilling of critical sour wells. This is reflected in the draft Interim Directive included as Appendix 5. The plan must include information as to how the public would be advised, protected, and evacuated if necessary, in the event of a blowout, and the plan must be discussed with the public. Emergency response plans were discussed extensively during Phase 1 of the inquiry and the Panel will be addressing the matter further in the Phase 1 report.

5.1.9 Drilling Plan

Participants generally agreed that drilling and geological data should be exchanged in order to improve drilling programs, but they recognized the constraints imposed by the confidential nature of geological data. Some participants were prepared to provide the ERCB with a copy of the drilling program, or a summary of it, and most indicated they already provide a copy to the drilling contractor.

The Panel urges operators to exchange geological information so that drilling programs can be designed in an optimum fashion for drilling into abnormal pressure and H_2S formations. As indicated in Appendix 5, a general description of the drilling plan and equipment to be used to drill a critical sour well must be submitted to, and approved by, the ERCB prior to the spudding of the well. The Panel will recommend that the review committee consider a method, suitable to industry and the ERCB, of exchanging geological information to assist in the development of drilling plans.

5.1.10 Mud System Design

The position taken by most participants was that mud system design should not be regulated, intentionally underbalanced mud programs should be eliminated, and appropriately safe mud programs should be followed for drilling into H_2S formations. Participants also commented on the importance of spare mud supply and differed in their opinions with respect to the use of stand-by tanks.

The Panel agrees that mud system design is a complex technical matter that must relate to the variable geological and drilling conditions at each well. It therefore does not lend itself to regulation. Nonetheless, very careful attention should be given to mud system design, particularly for high pressure H_2S formations with appropriate consideration being given to anticipated geological conditions in critical zones (pressure, permeability, formation fluids), the capacity of mud tanks, mud pH control, high speed mixers, and H_2S scavengers. The Panel recommends that this item be included for consideration by the review committee, including the possibility of a code of practice for mud system design.

5.1.11 Alberta Code of Practice for Drilling

The development of an Alberta code of practice for drilling with emphasis on sour gas wells was favoured by some participants. It was suggested that certain of the current regulations could be incorporated into a code of practice along with matters such as drill string design, drilling procedures, material and equipment specifications, and requirements for H_2S resistant blowout prevention equipment.

The Panel believes that the possibility of a code of practice for drilling should be considered by the review committee as a high priority.

5.2 Secondary Recommendations

5.2.1 Well Ignition

The participants suggested that a blowout well should not be automatically ignited because of the resulting damage to well control equipment, which in turn, would likely lengthen the duration of the blowout. It was suggested that the operator be given some time in which to formulate a control plan before ignition is considered.

The Panel agrees that a blowout well should not be automatically ignited in every instance but believes, because of the potential impact of certain wells at certain locations, that immediate ignition may be a necessity in some cases. The decision procedure as to whether the well should be intentionally fired in case of a blowout should be part of the emergency plan for sour wells. The Panel notes that because of the potential consequences which may occur, other Government departments and the public should be involved in determining ignition criteria. The Panel understands that the ERCB will initiate discussion in this regard with industry, Government, and the public. In the interim, if deemed appropriate by the ERCB, specific well licences will include a condition that the well be immediately ignited in case of a blowout.

5.2.2 Winter Drilling

Some participants expressed concern regarding a higher incidence of well problems, including blowouts, during winter months. Others suggested the statistics were being misinterpreted, and in any case any problem that existed could be eliminated by ensuring that the equipment was adequate for winter drilling.

The Panel believes that winter drilling can be conducted in a safe and effective manner providing the operator and contractor are sufficiently careful to ensure the adequacy of equipment and procedures to account for the severity of conditions.

The Panel recommends that the review committee consider the development of practical guidelines for equipment capabilities for winter drilling and the incorporation of them in any Alberta code of practice for drilling.

5.2.3 Contractors' Responsibility

One participant suggested that contractors should be given increased responsibility for the consequences of well control problems. The industry participants were united in their opposition to changing the existing contractual arrangements between the operator and the contractor.

The Panel believes that the responsibility for safe drilling practice must reside with the operator licensed to drill the well. It recognizes and supports the concept that certain requirements be contractually imposed on the drilling company, but does not believe that changes should be made to the existing situation where the operator has final responsibility.

5.2.4 Blowout Insurance

Insurance against blowouts was suggested to be far more expensive than small operators could afford. However, it was indicated that most major operators would have either blowout insurance or other corporate insurance that would cover a blowout incident.

The Panel is concerned that an uninsured operator with limited resources could have a major blowout which, in turn, could result in major economic impact to be covered by the public purse. The Panel understands that the ERCB intends to investigate further the need for and availability of blowout insurance and to consider whether it should be a requirement of each licensee.

5.2.5 Blowout Equipment Co-operative

A co-operative pool of blowout control equipment was suggested for use by any operator in the Province to assist in well control operations following a blowout. The CPA said it has maintained an equipment co-operative for several years at Golden Spike, Alberta, but the equipment has only been called out on three occasions and has never been used. This is apparently because the blowout control experts usually insist on using their own equipment.

Although the Panel can understand that blowout control experts in their very high risk work would want to use familiar equipment, it also believes that a pool of some blowout control equipment could be maintained and be of assistance to operators. The Panel recommends that the review committee give further consideration to this matter.

5.3 Other Recommendations

5.3.1 Safety

Safety concerns were raised by some participants in the inquiry who questioned the adequacy of the current regulations for breathable air supply on drilling rigs, the training in its use, and safety training for supervisors. Discussion also covered the length of a reasonable workday under stress conditions.

The Panel notes that the question of safety of workers at rig sites is within the jurisdiction of the Occupational Health and Safety Division of the Alberta Department of Workers' Health, Safety and Compensation, but believes that consideration of these matters should be initiated. The Panel will request that the ERCB contact the Occupational Health and Safety Division to initiate discussions on the matters set out in Appendix 8.

6 FINDINGS

Based on the evidence presented during Phase 2 of the inquiry, the Panel finds that

- The Alberta blowout experience appears comparable to that of other jurisdictions and costs vary greatly depending on the blowout severity.
- The Alberta blowout rate has steadily declined since the early 1970s, but sour gas blowouts continue to represent a disproportionate share of the total.
- It is probably not possible to completely prevent blowouts in Alberta but it is possible to reduce the frequency of blowouts by appropriate action.
- It is particularly important to develop and implement special measures that would be designed to prevent the blowout of "critical sour wells" and an ERCB draft Interim Directive is being issued for that purpose. It defines a critical sour well and requires approval by the ERCB, prior to spudding, of a general drilling plan, the equipment to be used, and an emergency response plan. Experienced supervisors and crews and increased inspections are also required.
- Industry and the ERCB need to work co-operatively to achieve the foregoing objectives and a review committee will be established with terms of reference and review items as summarized in Appendices 6 and 7 and referred to later in this section.

Some of the specific findings of the Panel are as follows:

- Addressing the role of human factors in preventing blowouts, improvements in crew training, rig inspection and reporting, drilling plans, mud system design, kick detection and response, and suspension of unsatisfactory rigs are likely to reduce blowouts and will be considered by the review committee.
- Improvements in equipment for H_2S drilling, with emphasis on blowout prevention equipment, drill pipe and degassers, will assist in reducing blowouts and will be considered by the review committee.
- Site-specific emergency response plans must be in place prior to drilling critical sour wells and the plans must reflect input from Government departments and the public.
- Exchange of information regarding rig inspections, blowout causes and circumstances, and drilling practices will assist in reducing blowouts and the most appropriate manner of doing this should be considered by the review committee.
- Criteria for ignition of blowout wells must be established with input from industry, Government, and the public. In the meantime, well licences for some wells in particular circumstances may include a condition for immediate ignition in the event of a blowout.
- Development of a code of practice for drilling, with emphasis on sour gas requirements, should be considered.
- The regulations regarding emergency breathing apparatus, air supply, and the safety of rig personnel need to be reviewed and the ERCB will initiate discussions with Alberta Workers' Health, Safety and Compensation.

ISSUED at Calgary, Alberta on 25 April 1984.

LODGEPOLE BLOWOUT INQUIRY PANEL

John Markham

V. Millard
Inquiry Panel Chairman

J. W. Markham, M.B.
Panel Member

G J DeSorcy

G. J. DeSorcy, P.Eng.
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F. A. Herbert, M.D.
Panel Member

R. S. Weaver, Ph.D.
Panel Member

APPENDIX 1 GLOSSARY OF TERMS

blooey line	the discharge pipe of a well being drilled with air as the drilling fluid
blowout	an uncontrolled flow of gas, oil, or other well fluids into the atmosphere
blowout preventer (BOP)	the valve-like equipment attached to the casing at a drilling rig to prevent a blowout.
certificate (first and second line)	certificates issued by the Petroleum Industry Training Service in blowout prevention and kick control procedures.
condensate	that part of natural gas that is liquid at normal atmospheric conditions.
BOP stack	the combination of valve-like devices, piping, and other fittings attached to the casing at a drilling rig.
casing (surface, production)	the steel pipe placed in a well to prevent the collapse of the hole and provide a conduit for fluids during the drilling and producing phases.
circulating	the pumping of drilling fluids down the drill pipe, out through the drilling bit, up the annulus, and back to the mud tanks.
coring	a drilling operation which uses a special bit to produce a cylindrical sample or core of the rock penetrated.
degasser (mud-gas separator)	a device which removes formation gas and air from drilling mud.
derrickman	the member of the rig crew who normally handles the upper end of the drill pipe from a position up on the derrick. He is also responsible for maintaining the drilling mud.
directional survey	a procedure to measure the direction and amount that a wellbore has deviated from the vertical.
diverter	a device used in air drilling which conducts the return air and drill cuttings from the top of the well to the flare pit.
driller	the member of the rig crew who operates the rig controls and is responsible for the rig and crew for one of the two or three shifts operating each day
drilling	the rotating of the drill pipe and bit and the circulating of drilling mud to cause penetration of formations.
drilling program	a document prepared by the licensee of the well which contains instructions, diagrams, and other pertinent information and is the approved procedure for drilling the well.
drilling spool	a spacer between components of the BOP stack, containing valved outlets.
drill pipe	the heavy seamless pipe used to rotate the drilling bit and circulate the drilling fluid.
fishing	to recover equipment such as broken drill pipe that has been lost in the wellbore.
formation	a subsurface layer or deposit that is composed throughout of substantially the same kind of rock.
H_2S scavenger	a material that deactivates any H_2S entering the wellbore.
hydrostatic pressure	the pressure exerted by a column of fluid such as the drilling mud in the wellbore.
inside BOPs	equipment designed to prevent blowout fluids from escaping up the inside of the drill pipe.
isopleth	an imaginary line surrounding a point of potential contaminant release, formed by joining points of equal contaminant concentration (similar to a contour line).
kick	the flow of gas, oil, water, or other formation fluids into the wellbore.

APPENDIX 1 (continued)

lost circulation	— the loss of drilling fluid from the wellbore into a permeable formation.
motorman	— the member of the rig crew who is responsible for the maintenance of the drilling engines, and who may also work on the rig floor.
mud (drilling)	— the liquid circulated down the drill pipe and up the annulus during drilling.
permeability	— a measure of the ability of fluids to flow through rock.
pH	— the acidity or alkalinity of a fluid; a measure of hydrogen ion activity.
porosity	— the open or void space within a rock.
rig manager (toolpush)	— the employee of the drilling contractor who is normally at the well site and is in charge of the entire drilling crew and drilling rig.
roughneck	— the members of the rig crew who usually work on the rig floor.
shear rams	— a component of the BOP stack that can cut or shear through the drill pipe and form a seal against well pressure.
sour gas	— natural gas containing H_2S in measurable concentration.
spud-in	— to start drilling the wellbore.
swabbing	— to pull the drill pipe up the wellbore too quickly and cause a sucking action within the wellbore.
testing	— a procedure to test the type and quantity of fluids contained in a formation.
tour reports (pronounced "tower")	— the daily record of activities at a drilling rig.
tripping (in/out)	— the process of pulling all the drill pipe out of the hole to change a drill bit or other bottom-hole equipment, and then lowering the drill pipe back into the hole.

APPENDIX 2 THOSE WHO APPEARED AT PHASE 2 OF THE INQUIRY

Participants and Representatives (Abbreviations used in Report)	**Witnesses**
F. G. Bercha and Associates Limited (Bercha)	F. G. Bercha, P.Eng. B. J. Griffin, P.Eng. R. I. Macdonald
Confer Consulting Ltd. (Confer)	G. M. Engbloom, P.Eng.
K. L. Shaw	K. L. Shaw
Energy Resources Conservation Board staff (ERCB staff) M. J. Bruni	W. G. Remmer, P.Eng. E. F. May B. E. McFarlane
Pembina Area Sour Gas Exposures Committee (PASGEC) D. P. Mallon	K. R. Bissett C. Whitelock
C. Sams	C. Sams
Canadian Association of Oilwell Drilling Contractors (CAODC) J. B. Ballem, Q.C.	P. C. Grigg
Canadian Petroleum Association (CPA) F. R. Foran	I. M. Parker, P.Eng. H. Rath, P.Eng. H. Maciej
Independent Petroleum Association of Canada (IPAC) D. O. Sabey, Q.C. B. K. O'Ferrall	W. A. Elser, P.Eng. J. K. Farries, P.Eng.
Canterra Energy Ltd. C. P. MacDonald	W. H. Sawotin, P.Eng. D. Lewis, P.Eng. R. Reid, P.Eng. R. L. Thomas
Dome Petroleum Limited W. M. Smith	H. J. Strain, P.Eng. A. Wichert, P.Eng.
Gulf Canada Resources Inc. J. D. Anderson	L. D. Demosky, P.Eng. D. S. Belczewski F. C. Smith A. E. Wallace, P.Eng.
Petro-Canada Inc. J. W. Gallagher	R. T. McGrath, P.Eng. K. C. Brown W. E. Roeske, P.Eng.
Shell Canada Resources Limited J. D. Courtright	J. R. Tilbe, P.Eng. J. Piaskoski B. Straub, P.Eng.

APPENDIX 2 (continued)

Participants and Representatives (Abbreviations used in Report)	Witnesses
A. Scovil Murray	A. Scovil Murray, P.Eng.
Alberta Government Departments (Government departments)	
A. R. Watson	
Amoco Canada Petroleum Company Ltd.	
A. L. McLarty	
S. E. Lipton	
Inquiry staff	
R. D. Schachter	
J. K. Moloney	
E. J. Morin, P.Eng.	

APPENDIX 3 BLOWOUTS OF DRILLING WELLS* — 1983 TO 1974

Well Name	Date	Duration (days)	Depth (metres)	Loss	Cause
CONGASCOME ET AL SHEKILIE 12-14-118-8 (W6M)	27 Feb 1983	9	1794	610 x 10^3m^3 of gas (2% H_2S)	lost circulation
AMOCO DOME BRAZEAU RIVER 13-12-48-12 (W5M)	17 Oct 1982	67	3067	to be dealt with report	in detail in Phase 1
CANSTAR CALUMET OV 2-24-98-12 (W4M)	11 Feb 1982	13	65	85 x 10^6m^3 of sweet gas; rig burned	unexpected shallow gas sand; no BOPs installed
DOME SULPETRO VALHALLA 8-23-74-9 (W6M)	18 Jan 1982	4	2042	3618 x 10^3m^3 of gas (trace of H_2S)	failure to keep hole full while tripping out followed by BOP failure
HB SHEKILIE 9-16-118-8 (W6M)	18 Nov 1981	4	1548	1613 x 10^3m^3 of gas (0.66% H_2S); rig destroyed	lost circulation
PETROFINA TEST HOLE B5 13-6-51-7 (W5M)	15 May 1981	1	201	28 x 10^3m^3 of sweet gas; fire damage to rig	air drilling with no diverter or BOPs
RENAISSANCE PETMT EDWAND 7-10-61-17 (W5M)	1 Dec 1980	3	648	566 x 10^3m^3 of sweet gas; rig burned	lost circulation; surface casing split
BLAKE ET AL STEEN 10-9-112-1 (W6M)	7 Feb 1980	25	70	no estimate of sweet hydrocarbon loss; major rig fire damage	unexpected shallow gas sand
AMOCO ET AL STEEP 7-28-66-7 (W6M)	22 Nov 1979	3	2338	280 x 10^3m^3 of sweet gas	swabbing with fishing tools
SHELL RANDALL 12-10-81-2 (W5M)	26 Feb 1979	1	484	no estimate of hydrocarbon loss (sweet); fire damage to rig	failure of bleed-off hose on blooey line while air drilling
GULF POC GOLD RIVER 6-18-70-15 (W4M)	20 Dec 1977	2	505	60 x 10^3m^3 of sweet gas	loss of casing cement to weak zone
GAMMA ET AL CESSFORD 6-30-23-10 (W4M)	19 Dec 1977	33	952	1860 x 10^3m^3 of sweet gas; rig destroyed	swabbing while tripping out

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* Blowouts of wells being drilled whether sour or sweet, oil or gas, have been included.

APPENDIX 3 (continued)

Well Name	Date	Duration (days)	Depth (metres)	Loss	Cause
AMOCO PACIFIC BRAZEAU RIVER 7-10-48-12 (W5M)	6 Dec 1977	28	3311	$16 \times 10^6 m^3$ of gas (25% H_2S); rig destroyed	swabbing while tripping out; frozen equipment
WESTCOAST AEC SUFFIELD 8-13-20-8 (W4M)	4 Dec 1977	2	940	$115 \times 10^3 m^3$ of sweet gas	swabbing while pulling drill-stem test tools
DOME LPGS FT. SASK. 15B-14-55-22 (W4M)	13 Mar 1977	2 (hours)	964	$30 \times 10^3 m^3$ of sweet gas	loss of hydrostatic head while repairing mud pump
SHELL 35 WATERTON 12-9-3-30 (W4M)	28 Feb 1977	2	3148	$56 \times 10^6 m^3$ of gas (14% H_2S)	swabbing while tripping out
HUSKY NEERLANDIA 6-30-61-5 (W5M)	18 Jul 1975	1	174	no estimates (sweet gas)	swabbing while tripping out (plugged bit)
CDN-SUP CANSO BADGER 6-3-17-17 (W4M)	14 Mar 1975	4	1145	$2433 \times 10^3 m^3$ of sweet gas	insufficient mud weight
HBOG OIL SANDS Evaluation Hole 7-28-96-11 (W4M)	23 Jan 1975	2	118	$21 \times 10^3 m^3$ of sweet gas; rig destroyed	swabbing while tripping out
SUN CESSLAND JENNER 6-9-22-9 (W4M)	5 Sep 1974	2½	772	$1817 \times 10^3 m^3$ of sweet gas	abnormally high formation pressure
SUNDANCE ET AL DUNVEGAN 10-18-82-5 (W6M)	28 Feb 1974	10½	1510	$1690 \times 10^3 m^3$ of sweet gas	lost circulation; production casing failure

APPENDIX 4 ERCB RIG INSPECTIONS

25 April 1984

Canadian Association of Oil Well Drilling Contractors
Canadian Petroleum Association
Independent Petroleum Association of Canada
Pembina Area Sour Gas Exposures Committee, Mr. K. R. Bissett

ERCB INSPECTIONS OF DRILLING RIGS

During Phase 2 of the Lodgepole Inquiry, ERCB staff presented evidence of the results of its inspections of drilling rigs from 1979 to mid 1983. The evidence indicated that on average, the rigs on 33 per cent of all wells drilled during this period were inspected, 47 per cent were found to be unsatisfactory in some respect, and 83 per cent of the unsatisfactory cases had one or more serious deficiencies.

This evidence resulted in considerable concern and controversy regarding the data, and confusion with respect to how it should be interpreted. The ERCB staff indicated that the statistics had been compiled to assist it in the selection of rigs to inspect, and not for the purpose of assessing the overall quality of drilling operations in the Province. The staff recommended that it and industry representatives should meet to review the inspection forms used by the ERCB as well as the definitions adopted for classifying deficiencies as ''serious''.

Other participants agreed with this proposal. The Panel also agreed with it, and recommended that this letter be sent. The purpose of it is to invite your association to appoint one or two representatives to a Drilling Rig Inspection Committee under the chairmanship of Mr. Bill Remmer of the ERCB.

The proposed terms of reference of that committee are:

1. Review the inspection frequency policies to ensure that the number of inspections is adequate.
2. Review the ERCB Drilling Rig Inspection Form and the related instruction guides to determine whether they are appropriate for individual rig inspections and also for determining whether the overall state of rigs in the Province is adequate.
3. Review whether the current basis used by the ERCB for classifying inspection deficiencies as ''serious'' is appropriate.
4. Consider and recommend a procedure whereby the results of ERCB rig inspections might best be communicated to the operators, the contractors, and the public.
5. Consider whether and in what manner the inspections by the operator and contractor might be incorporated into the system.
6. Consider whether a rework of inspection results for 1983, using the appropriate definition of ''serious'', is possible and appropriate.

The Board considers this to be an urgent matter and seeks your assistance. It has requested Mr. Remmer to complete the review and submit recommendations by 30 June 1984. That report will be a public document.

I would appreciate your advice as to the names of your representatives by 10 May 1984. Attached is a package of information that will be relevant to the committee.

Yours truly,

V. Millard
Chairman

VM/kl
Enclosures

APPENDIX 5 DRAFT INTERIM DIRECTIVE ID 84-

To: All Operators, All Drilling Contractors,
and the General Public

BLOWOUT PREVENTION AT SOUR WELLS

Reference is made to the recently completed inquiry respecting the 1982 blowout at the AMOCO DOME BRAZEAU RIVER 13-12-48-12 well. The second phase of that inquiry was not related to the specific blowout but dealt with the broad subject of the prevention of blowouts in the Province as a whole

There was considerable agreement among most participants on a number of the matters dealt with. One such matter related to the need for special safeguards against blowouts in the drilling of certain "critical sour wells". Discussion also took place respecting plans that would minimize impacts on the public should such a blowout occur.

The Board believes this matter to be of considerable importance and urgency and consequently is issuing this draft Interim Directive to define certain wells it considers to be "critical" and to establish requirements for the drilling of those wells. It recognizes that the special requirements will result in somewhat higher drilling costs for these wells but is convinced that these additional costs are warranted particularly having in mind that the potential cost of a blowout at one of these wells is very large. It should also be noted that the special requirements and related costs would apply only to a small portion of the total number of wells drilled in the Province. In 1983, fewer than 50 of the wells drilled would have been designated as "critical sour wells".

The Board intends that these interim requirements will apply for an approximate 6-month period, during which time the adequacy of them will be tested. Comments with respect to these requirements are invited prior to the end of October 1984, from industry, the public, and any other interested parties. The Board would expect to issue a new directive and, as necessary, amend the regulations at the end of the trial period, thus establishing a long-term policy respecting critical sour wells. At that time the Board will review and update, and combine where appropriate, its directives with respect to sour gas. (Interim Directive ID-OG-76-2, Emergency Procedure Plans For Sour Gas Facilities. Interim Directive ID 81-3, Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments.)

This draft Interim Directive is being included in the Phase 2 inquiry report. A task force or committee is being established to review certain of the matters discussed at Phase 2 of the inquiry. The Board believes that the committee should review the appropriateness of this draft directive and the policy it establishes, and should provide its comments by the end of October. If in the meantime and as a result of applying the requirements on an interim basis, particular problems or questions arise, the Board will refer such questions to the committee for its comments.

This interim policy does not change the minimum distance requirements separating sour gas facilities from residential and other developments as set out in Interim Directive ID 81-3. The policy respecting critical sour wells is as follows:

Definition

For blowout prevention purposes a critical sour well is defined as follows:

(a) any proposed well from which the maximum potential hydrogen sulphide (H_2S) release rate is greater than 2.0 cubic metres per second (m^3/sec),

(b) any proposed well from which the maximum potential H_2S release rate is greater than 0.3 m^3/sec and less than 2.0 m^3/sec if the well is to be located within 5 kilometres (3.1 miles) of an urban centre*, or

(c) any proposed well from which the maximum potential release rate is greater than 0.01 m^3/sec and less than 0.3 m^3/sec if the well is to be located within 1.5 kilometres (0.93 miles) of an urban centre, or

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* An urban centre is defined as a city, town, village, or other incorporated centre, and for the purpose of this directive includes any similar development the Board may designate as an urban centre.

APPENDIX 5 (continued)

(d) any other proposed well which the Board classifies as a critical sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area in which the well is to be located, and the expected complexities in the drilling of the well.

Special Requirements

The applicant for a licence for a critical sour well must satisfy the following special requirements:

1 A satisfactory emergency response plan must be filed with the Board prior to the spudding of the well. The plan must meet the minimum content requirements set out in ID-OG-76-2 and must describe the manner in which the public would be notified, have their safety protected, and be evacuated if necessary, in the event of a blowout. The plan must also have been discussed with members of the rural public and urban representatives that reside within the maximum 100 parts per million isopleth which could be associated with the well. It should also deal with the manner in which the decision would be made as to whether the well would be intentionally ignited in case of a blowout.

This requirement for an emergency response plan is in addition to those set out in ID-OG-76-2 for gas plants and pipelines. Also, pursuant to section 7.060 of the Oil and Gas Conservation Regulations, the Board may continue to request emergency response plans for certain wells which are not ''critical sour wells'' under this directive.

2 A general description of the drilling plan and the equipment to be used to drill the well must be submitted to and approved by the Board prior to the spudding of the well. The plan would include geological data as necessary but be general in nature and briefly describe any serious drilling problems which may be expected and the manner in which they would be handled. It should also briefly address critical equipment such as the BOPs (including a discussion as to whether or not shear rams will be installed), the drill string, the degasser, the mud system, and procedures, to ensure that all such equipment is fully operative prior to penetrating the critical zone. The plan should also provide for the taking of a directional survey unless the operator can satisfy the Board that it is not needed.

3 The operator must satisfy the Board prior to spudding that supervision during the drilling of the well will be adequate. This will require on-site supervisors with Level 2 certification and some experience in drilling in sour areas. During critical periods at the well, such as drilling into the sour formation, sufficient supervision must be available so that no individual supervisor is required to work a shift longer than 12 hours.

4 The operator must satsify the Board prior to spudding that the drilling crew and key service personnel on the rig are adequate in number and sufficiently qualified. A minimum 5-man drilling crew will normally be required and at least some of the personnel should have experience in sour areas.

5 The operator must satisfy the Board prior to spudding that adequate safety personnel and safety equipment for workers will be on site at all critical times.

6 Intermediate casing set to an appropriate point above the zone from which sour gas or oil is expected will normally be required. However, the Board may exempt certain wells from this requirement if the applicant can demonstrate with a high degree of certainty that intermediate casing is not warranted.

7 A complete inspection and blowout prevention drill will be required prior to drilling out the surface casing and the intermediate casing and before penetrating the formation expected to contain sour gas. The Board field office must be notified at least 48 hours ahead of time so that staff may participate if judged appropriate.

8 If the well is not abandoned, completion and servicing operations will not be permitted without prior consent from the Board. Consent will be granted only if the Board is satisfied that proper equipment and trained personnel will be used and that adequate precautions to prevent a blowout will be taken.

APPENDIX 5 (continued)

Additional Information to Support Well Licence Applications

The maximum potential H_2S release rate must be submitted as part of a licence application for any well and should be calculated on the basis of the maximum flow rate and H_2S content which can be expected. It should reflect all information available from wells in the area and a realistic engineering approach which recognizes the expected geological setting and reservoir fluid. A detailed description of the type of information required is set out in Attachment I.

Information respecting the maximum potential release rate along with plans for satisfying the above special requirements should be submitted with a licence application for any well which would be a ''critical sour well'' in accordance with the definition in this directive. In instances where the Board decides that a critical designation should be attached to a well which does not otherwise qualify in accordance with this directive, the applicant for a licence will be sent a deficiency letter requesting information to satisfy the special requirements.

The additional information provided the Board to determine the maximum potential H_2S release rate or to satisfy the above listed special requirements will, with certain exceptions, be considered as public information. Where geological data or personal information respecting individuals is provided as part of the submission, the Board will, upon request from the applicant, consider it as confidential. Such information should be included in a separate volume to avoid inadvertant release. In situations where a well licence application goes to a public hearing the matter can be decided on the basis of only that information which is public. However, the applicant will be provided with an opportunity to reclassify as public, all or a modified part of the data originally filed as confidential.

Comments regarding this directive from industry, the public, or other interested parties should be addressed to the Manager, Development Department (297-8169).

Applicants requiring further information regarding well licensing should address their inquiries to the Well Licensing Section (297-8159) and regarding emergency response plans to the Environment Protection Department (297-8324).

ISSUED at Calgary, Alberta on 25 April 1984.

Vernon Millard

Vernon Millard
Chairman

Attachment

ATTACHMENT I (ID 84-)

Where an application is made to the Board for a well licence, the applicant shall include in the application the information required in either A or B, as applicable.

A A statement and supporting evidence to the effect that none of the formations to be encountered during the drilling of the well are expected to contain hydrogen sulphide (H_2S).

or

B 1. For each formation to be penetrated which may contain H_2S:

   (a) the maximum expected concentration of H_2S, and the source of this information,

   (b) the maximum expected flow capability at the surface for the case where the unstimulated formation is open to the wellbore as during drilling, and for the case where the well has been completed and the formation stimulated, and the method and information used to determine these values,

   (c) the calculated potential H_2S release rate expressed in the units of cubic metres per second for each of the two cases referred to in (b) above.

2. The maximum potential uncontrolled release rate of H_2S at the stage in the drilling of the well where the sum of the release rates from each formation open to the wellbore is a maximum.

3. The maximum potential uncontrolled release rate of H_2S during the producing stage for the well.

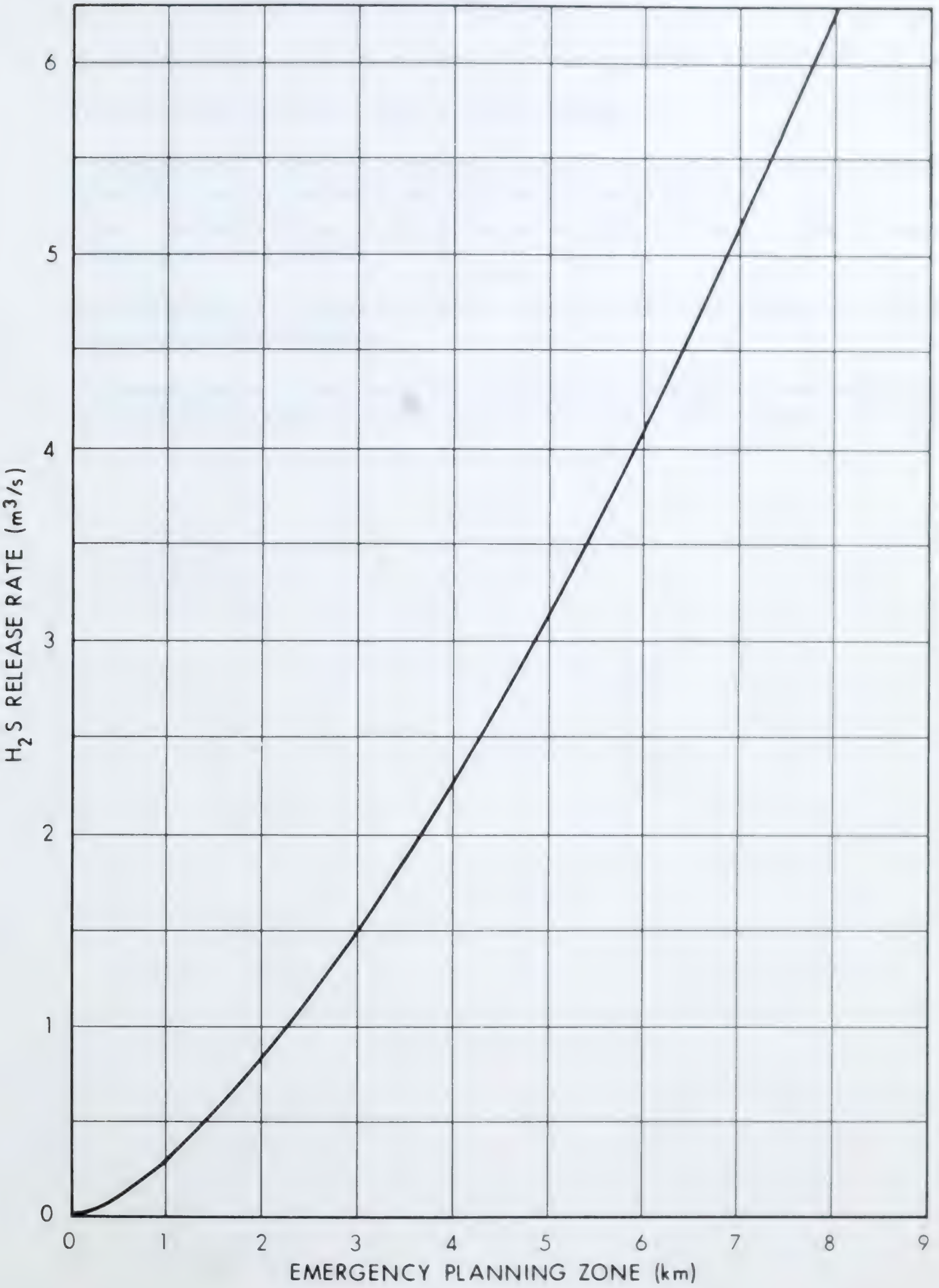
4. The radius of the emergency planning zone for each of 2 and 3 above, determined from the graph in Figure 1 to this Attachment.

5. A map showing the location of all residences and public facilities located within the larger of the emergency planning zones.

6. A statement of the distance to the nearest permanent residence, public facility, rural subdivision, or urban centre beyond the larger of the emergency planning zones, plus an indication of the population density in the general area beyond the planning zone a distance approximately equal to the radius of the planning zone.

It is emphasized that a realistic, responsible engineering approach must be taken. The expected geological setting and reservoir fluids to be encountered must be recognized along with all relevant tests and analyses for the area. In order that the best possible information be available all operators are urged to file the results of tests and analyses with the Board as soon as possible following the completion of the tests.

FIGURE 1 TO ATTACHMENT I
EMERGENCY PLANNING ZONES FOR SOUR GAS WELLS



APPENDIX 6 BLOWOUT PREVENTION REVIEW COMMITTEE TERMS OF REFERENCE

1. Membership will consist of two representatives from each of the ERCB, CAODC, CPA, and IPAC.

2. The Chairman and the Secretary will be the ERCB representatives.

3. The Committee will, through sub-committees if appropriate, investigate, develop recommendations, and report to the parent organizations on each of the subjects listed in Appendix 7.

   Subjects identified as high priority will be reported on or before 1 November 1984. All others will be reported on or before 1 July 1985.

4. The first meeting of the Committee will be held no later than 1 June 1984, and the Committee will remain active as long as the need continues.

5. Government agencies and representatives of the public will be consulted on those matters identified in Appendix 7 and they will be considered for membership on the relevant committees or sub- committees

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APPENDIX 7 BLOWOUT PREVENTION REVIEW COMMITTEE TABLE OF ACTIVITIES AND PRIORITIES

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
1	Critical Sour Well Definition	High	5.1.1
2	Training — Human factors — Driller and crew — Hands-on crew training — 3rd-line supervisors — Surprise drills — Review certification levels — Review certification periods — H_2S awareness — Management awareness — Follow-up — Effectiveness	High	5.1.2
3	Enforcement — Suspension of BOP tickets	Moderate	5.1.3
4	Inspection — More rigorous & frequent function testing of BOPs — Drilling out casings — Entering critical formations — Identify critical depths — Rig deficiency statistics[1]	High	5.1.4
5	Supervision — Special teams for H_2S wells — Two supervisors on critical wells — 2nd-line certificate — 12-hour shifts — BOP drills	High	5.1.5

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[1] The ERCB staff has already started work with the Phase 2 participants to resolve the difficulties with these statistics.

APPENDIX 7 (continued)

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
6	Special Drilling Equipment — Improve kick detection equipment — Monitoring — Degassers — Shear rams[2] — Inside BOPs (floats) — Drill pipe design and metallurgy — H_2S resistant equipment — Location of lower drilling spool — Location of HC valve — Manifold redundancy — Casing pressure gauges — BOP configuration — Master controls location — More automation — Equipment specifications — Drill-string inspection	High	5.1.6
7	Information Exchange — Gather drilling data	Moderate	5.1.7
8	Drilling Plan — Well planning execution — Kick detection/response — Drilling procedures entering critical zone — Tripping and coring procedures — Entering the formation — Lease preparation — Directional surveys — Drill-stem testing — Exchange geological information	Moderate	5.1.9

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[2] PASGEC specifically requested input to these items and the committee must ensure that it is kept informed.

APPENDIX 7 (continued)

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
9	Mud System Design — Underbalanced programs — Conservative mud weights — Mud capacity — pH — H_2S scavengers — Geological conditions — Mud and gas monitoring[2] — Drilling fluids	Moderate	5.1.10
10	Code of Practice for Drilling — Drilling procedures — Tripping and coring — Formation testing — Drill-string design — BOP equipment — Equipment specifications — H_2S-resistant materials	High	5.1.11
11	Winter Drilling Guidelines	Moderate	5.2.2
12	Blowout Equipment Co-operative	Moderate	5.2.5

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APPENDIX 8 MATTERS TO REFER TO OCCUPATIONAL HEALTH AND SAFETY TABLE OF ACTIVITIES AND PRIORITIES

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
1	Health and Safety — Emergency breathing equipment — Air supply — Training for Supervisors — 12 hour shifts — Safety personnel at critical times — Air monitoring — Respiratory equipment and training	High	5.3.1

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REPORT OF THE
DRILLING RIG INSPECTION COMMITTEE
FORMED IN ACCORDANCE WITH
ENERGY RESOURCES CONSERVATION BOARD DECISION D84-5,
PROCEEDING 830007

29 June 1984

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CONTENTS

Page

1 INTRODUCTION 1

2 RIG INSPECTION FREQUENCY 1

2.1 ERCB Inspections
2.2 Operator and Contractor Inspections

3 DRILLING RIG INSPECTION POLICIES 3

3.1 ERCB Inspection Form and Manual
3.2 Operator and Contractor Inspections

4 ASSESSMENT OF DRILLING RIG QUALITY 4

4.1 Individual Rigs
4.2 Serious Classification
4.3 Overall Rig Quality

5 COMMUNICATION OF ERCB INSPECTION RESULTS 6

5.1 Individual Rig Inspections
5.2 Summary Reports
5.3 Analysis of Inspection Results

6 1983 ERCB INSPECTION RESULTS 7

7 CONCLUSIONS 11

UNIVERSITY OF ALBERTA

TABLES

		Page
Table 1	1983 Inspection Coverage and Results	8
Table II	1983 Unsatisfactory Inspections with "Serious Deficiencies"	9
Table III	1983 Most Frequent Serious Inspection Items	10

UNIVERSITY OF ALBERTA

ATTACHMENTS

		Page
I	Terms of Reference, V. Millard's Letter of 25 April 1984	12
II	Members - Drilling Rig Inspection Committee	13
III	ERCB Drilling and Servicing Operations Inspection Report	14
IV	Serious Rig Deficiencies	15
V	Example Analysis, 1983 ERCB Inspection Results	18

1 INTRODUCTION

The Energy Resources Conservation Board (ERCB), in its Lodgepole Blowout Inquiry, Phase 2, Decision Report D84-5, requested formation of a "Drilling Rig Inspection Committee", made up of representatives of the Canadian Petroleum Association, Independent Petroleum Association of Canada, Canadian Association of Oil Well Drilling Contractors, the public, and the ERCB staff.

This committee was to review:

- drilling rig inspection frequencies and policies of the ERCB, operators, and contractors,
- the interpretation of the inspection results on an individual and provincial basis, and
- how the results might be communicated to the operators, the contractors, and the public.

The terms of reference of the committee are detailed in a letter from Vern Millard, dated 25 April 1984, which is included as Attachment I to this report.

The committee members are listed in Attachment II.

2 RIG INSPECTION FREQUENCY

2.1 ERCB Inspections

The committee members agreed that the role of the ERCB staff is to spot check rigs and that it is physically impossible for the ERCB staff to inspect each rig on every well drilled. It was agreed that the ERCB should continue with its current selection policy[1]:

- Inspect all critical sour wells a minimum of two or three[2] times; that is, witness a complete pressure test and conduct detailed inspection(s) prior to drilling out of the surface and intermediate casing or before penetrating the first sour zone.
- Conduct at least one inspection of rigs drilling non-critical sour gas wells.

---

[1] The current policy was formulated and implemented in early 1984.

[2] A minimum of three inspections should be conducted where drilling duration permits or where distance to population density dictates.

- Place emphasis on sour oil wells.
- Place emphasis on rigs with poor performance histories or new rigs in the province.
- Place emphasis on all rigs immediately following or during the first winter cold spell to ensure that equipment is adequately heated.
- Place emphasis on witnessing blowout preventer pressure tests, particularly for new or poor performance rigs.
- Inspect drilling operations where environmental conditions are included on the well licence.

The committee agreed that the historical ERCB inspection frequencies[3] were adequate for sour gas and deeper wells; however, increased emphasis should be placed on shallow wells, Classes[4] II and III. However, the committee recognized the difficulties in inspecting rigs that move every 2 or 3 days. The committee concluded that the ERCB inspection frequency should be in the order of:

- 20 per cent for Class[4] II wells,
- 30 per cent for Class III wells,

---

[3] Inspection frequency is the percentage of rigs inspected each year based on the total wells drilled. For example, 100 per cent inspection frequency would be an inspection of each rig on every well drilled.

[4] From Oil and Gas Conservation Regulation 8.131; except for Class I, the blowout prevention class is based on projected well depth as follows:

- Class I, no surface casing has been run
- Class II, 0 to 750 metres deep
- Class III, 750 to 1800 metres deep
- Class IV, 1800 to 3600 metres deep
- Class V, 3600 to 6000 metres deep
- Class VI, greater than 6000 metres

- 50 per cent for Class IV wells, and
- 100 per cent for Class V and VI wells.

This equates to an overall inspection coverage of 30 to 35 per cent based on historical drilling activity.

2.2 Operator and Contractor Inspections

The committee agreed that the operator of the well should be more involved with inspections of drilling rigs. Daily "walk arounds" should be conducted by the contractor and operator[5] in conjunction with the daily function testing of the BOP equipment. They should then initial the tour report, signifying that the daily inspection was completed. In addition, detailed inspections utilizing a check sheet should be conducted by the contractor in conjunction with the operator[5]. These inspections should be conducted in conjunction with the weekly BOP drill. The results of the detailed inspection should be recorded in the tour report and signed by both the operator and contractor.

3 DRILLING RIG INSPECTION POLICIES

3.1 ERCB Inspection Form and Manual

The committee reviewed in detail the ERCB Drilling and Servicing Operations Inspection Report form and the associated Rig Inspection Manual, and no major deficiencies were identified. Minor clarifications have been made to the manual as a result of the committee review.

Regarding the inspection form, the committee felt that a distinction should be made between inspection items associated directly with the rig blowout preventer capability and those associated with other operations. In addition, the ERCB inspector should not record an inspection as unsatisfactory for items associated with the initial pressure tests and associated work. The purpose of this work, prior to the initial drill out, is to identify and correct deficiencies. However, the ERCB should comment on items requiring attention. These modifications should place a better perspective on rig quality.

---

[5] The operator's representative should participate in the inspection if available.

In regard to rig quality, the committee agreed that an additional set of boxes and comments identifying "serious" deficiencies should be added to the form so that all parties concerned would better recognize the condition of the rig. To confirm this understanding, both the operator and the contractor should sign the ERCB inspection form at the completion of the ERCB inspection.

3.2 Operator and Contractor Inspections

Section 2.2 dealt with the necessity of daily and weekly inspections by both the contractor and the operator. The committee agreed that development of a standard check sheet for the industry would be difficult, if not impossible, taking into consideration the number and different types of inspections required by operators, contractors, and the various Acts and Regulations.

The committee believed that operators and contractors should expand their existing forms to include the requirements of the Oil and Gas Conservation Regulations. This could be accomplished by including the items listed on the ERCB rig inspection form (Attachment III) and/or the ERCB Rig Inspection Manual.

In order to incorporate the results of the operator/contractor inspections into the system, the committee recommends that only the results of these inspections be recorded on the tour sheet by either listing the deficiencies found or by a statement that the rig appears to conform to the requirements of the Oil and Gas Conservation Regulations. The ERCB staff would then spot check the tour reports for the results of these inspections, and it would not be necessary for the ERCB to obtain or review the actual operator/contractor inspection forms.

4 ASSESSMENT OF DRILLING RIG QUALITY

The Board requested the committee review the adequacy of the ERCB rig inspection policy in determining whether it is appropriate for an individual rig, and whether the data could be used in making an assessment of the overall state of the rigs in the province.

4.1 Individual Rigs

The committee agreed that the ERCB inspections are detailed enough to assess the quality of the rig, in regards to well control, at the time of the inspection. The changes suggested for the ERCB rig inspection form should further improve the determination of rig quality.

The committee noted that, because the ERCB inspects over 150 items during an inspection, any one item could lead to an ERCB classification of an unsatisfactory inspection. Therefore, a severity classification should be adopted.

The committee agreed that, although unsatisfactory items are a contravention of the Regulations and therefore significant, there are some items which must be corrected immediately while others could be delayed to a more convenient time. The committee therefore recommends that emphasis be place on "serious" items.

4.2 Serious Classification

The committee modified the existing ERCB staff definition of "serious" and recommended the following definition be adopted:

> Serious - "Where a deficiency occurs, subsequent to the initial drill out, which could contribute to an operational failure of the blowout prevention equipment or may restrict the crew's ability to safely detect, shut-in the well, and/or circulate out a well kick and maintain control of the well."

Where a serious deficiency occurs, the committee agreed that drilling operations should be suspended until the item has been corrected. Examples of serious items are included in Attachment IV. This list is not all inclusive, because situations such as multiple unsatisfactory items and the type of well must also be considered in the assessment of "serious".

The committee recommends that the serious definition, plus all serious and significant items, be included in the ERCB Rig Inspection Manual. This manual should be distributed to the industry associations so that all parties can be familiar with the serious classification and ERCB inspection procedures.

4.3 Overall Rig Quality

The only method available to determine the overall state of rigs in the province would be to inspect each rig or every well drilled within a given time frame. The committee agreed that this is not a practical solution.

Utilization of the ERCB inspection results should not be extrapolated to reflect overall provincial rig quality. Some of the problems with an extrapolation are:

- The ERCB inspections are biased towards rigs which have a history of problems.

- Emphasis is placed on different classes of rigs and types of wells which may not be similar to the provincial distribution.
- Multiple inspection of the same rig may occur throughout the year.
- Items may be classified as unsatisfactory that relate to lease and not rig conditions.

The committee recommends that no attempt be made to equate the results of the ERCB inspections to the overall provincial situation. However, analysis of the ERCB inspections should be carried out where unsatisfactory items are identified to determine serious and significant items ranked by frequency of occurrence.

The results of these analyses should be made available to operators, contractors, and to the public to indicate where remedial action should be focused.

5 COMMUNICATION OF ERCB INSPECTION RESULTS

5.1 Individual Rig Inspections

The committee agreed that ERCB inspection results must be communicated to both the operator and drilling contractor at the time of inspection. The ERCB staff should also call the operator's drilling representative, send letters, and/or call meetings to discuss "serious" items with both the operator and contractor.

5.2 Summary Reports

The committee recommends that the ERCB staff compile quarterly summary reports, by operator and contractor. Each operator and contractor should receive the report of his operations. Depending on criteria to be established by the ERCB staff, on receipt of a summary report the operator or contractor might be requested to outline steps that would be taken to reduce the number of unsatisfactory items.

5.3 Analysis of Inspection Results

An analysis of the ERCB inspection results should be completed in order to put the results in perspective and to indicate where emphasis should be placed by the ERCB, operators, and contractors. The analysis should include:

- the total number of wells drilled (by class or other suitable breakdown),
- the number of active rigs,
- the number of ERCB inspections conducted,
- a listing of the "serious" items found and their frequency, and
- a listing of the most frequent unsatisfactory items.

An example of an analysis is included as Attachment V.

The committee recommends that the analysis be distributed on an annual basis to the Canadian Association of Oil Well Drilling Contractors, the Canadian Petroleum Association, and the Independent Petroleum Association.

This analysis should also be available to the public, and the committee recommends that it be included with a publication of the causes and circumstances of blowouts.

6 1983 ERCB INSPECTION RESULTS

The committee felt it was appropriate to rework the 1983 inspection results utilizing its definition of serious.

A review of the 1983 ERCB drilling rig inspection reports by the committee found that there were:

- 4616 wells drilled,
- 1664 rig inspections, and

9 560[6] unsatisfactory rig inspections.

The following table illustrates the distribution of these inspections.

---

[6] The 63 unsatisfactory inspections recorded prior to initial drill out were excluded as recommended in section 3.1.

TABLE I 1983 INSPECTION COVERAGE AND RESULTS

Well Class[4]	Wells Drilled	Inspections	Per Cent Inspection Frequency	Unsatisfactory Inspections
1	84	15	18	7
2	1369	214	16	79
3	2180	747	34	259
4	960	646	67	214
5	23	42	>100	1
6	0	0	-	0
TOTAL	4616	1664	36	560

The committee members reviewed all unsatisfactory inspections to determine what deficiencies lead to the unsatisfactory inspections and whether or not a "serious" condition existed. The committee felt that it would be appropriate to use the "serious" classification regardless of the depth of the well and the operation being carried out[7] at the time of the inspection. The results of this review are shown in Table II below:

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[7] Subsequent to the initial drill out as recommended in section 3.1.

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TABLE II 1983 UNSATISFACTORY INSPECTIONS WITH A "SERIOUS" DEFICIENCY

Well Class[4]	Number of Unsatisfactory ERCB Inspections	"Serious"	Per Cent "Serious"[8]
1	7	2	29
2	79	61	77
3	259	145	56
4	214	108	50
5	1	0	0
6	0	0	0
TOTAL ALL CLASSES	560	316	56

The committee felt that its analysis of the 1983 inspection results, with respect to serious deficiencies, gave it a better perspective on rig quality. The committee recommended that similar analyses be conducted by the ERCB staff and industry on an annual basis. The computerization of "serious" deficiencies should assist in the analysis.

The committee agreed that a concerted effort by all parties must be taken to reduce the number of rig deficiencies - especially for the serious category. To assist in that regard, the committee prepared the following table which lists the 10 most frequent serious items.

---

[8] Per cent serious was calculated for each well class by dividing the number of serious inspections by the number of unsatisfactory ERCB inspections. For example, Class 1 was 2 divided by 7.

TABLE III 1983 MOST FREQUENT SERIOUS INSPECTION ITEMS[9]

Item		Per Cent of Total Serious Items[9]
1	Mud-tank level monitoring device not operating	24
2	Bleed off and flare lines not staked down or secured	12
3	Trip records not completed	10
4	BOP remote controls did not function	6
5	Trip-tank level indicator not operating	5
6	Hydraulically-operated valve failed or control did not function	4
7	Bleed off line improperly designed (improper Tees or fluid turns)	4
8	Driller did not have first line certification	4
9	BOP failed to operate	3
10	Crew BOP drills not conducted	3
	TOTAL	75

The committee noted that most of the serious items listed in Table III were attributable to a lack of awareness, attitude and maintenance. Considering this, the committee believes that both the operator and contractor must increase training and conduct daily and detailed inspections, as recommended in sections 2.2 and 3.2, to detect deficiencies and correct the items as soon as they are found.

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[9] A total of 435 serious items were recorded for the 316 serious inspections. The percentages calculated in Table III are based on the 435 serious items.

7 CONCLUSIONS

The committee concluded that:

- ERCB staff should continue with its current drilling rig selection policy. Increased emphasis should be placed on rigs drilling shallow wells.
- Operators and contractors should be more involved in inspecting drilling rigs. The operator and contractor should initial the tour report at the completion of a daily rig inspection. The results of a weekly detailed inspection should be recorded on the tour report accompanied by signatures of the operator and contractor representatives.
- The ERCB inspection form and manual should be expanded to include a "serious" classification of inspection items. The ERCB manual should be distributed to the industry associations.
- Both the operator and contractor's representatives should sign the completed ERCB inspection form.
- ERCB inspection results should not be extrapolated to reflect overall provincial rig quality.
- Emphasis should be placed on "serious" deficiencies including suspending drilling operations until "serious" items are corrected.
- The majority of 1983 "serious" deficiencies were attributable to a lack of awareness, attitude and maintenance. These items must be addressed and corrected by the operators and contractors through daily and weekly inspections and increased training.
- Quarterly ERCB inspection summaries should be distributed to each contractor and operator. Yearly analysis should be conducted, by the ERCB and Industry, and the results distributed to the industry associations and made available to the public.

ATTACHMENT I

25 April 1984

Canadian Association of Oil Well Drilling Contractors
Canadian Petroleum Association
Independent Petroleum Association of Canada
Pembina Area Sour Gas Exposures Committee, Mr. K. R. Bissett

ERCB INSPECTIONS OF DRILLING RIGS

During Phase 2 of the Lodgepole Inquiry, ERCB staff presented evidence of the results of its inspections of drilling rigs from 1979 to mid 1983. The evidence indicated that on average, the rigs on 33 per cent of all wells drilled during this period were inspected, 47 per cent were found to be unsatisfactory in some respect, and 83 per cent of the unsatisfactory cases had one or more serious deficiencies.

This evidence resulted in considerable concern and controversy regarding the data, and confusion with respect to how it should be interpreted. The ERCB staff indicated that the statistics had been compiled to assist it in the selection of rigs to inspect, and not for the purpose of assessing the overall quality of drilling operations in the Province. The staff recommended that it and industry representatives should meet to review the inspection forms used by the ERCB as well as the definitions adopted for classifying deficiencies as ''serious''.

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Other participants agreed with this proposal. The Panel also agreed with it, and recommended that this letter be sent. The purpose of it is to invite your association to appoint one or two representatives to a Drilling Rig Inspection Committee under the chairmanship of Mr. Bill Remmer of the ERCB.

The proposed terms of reference of that committee are:

1. Review the inspection frequency policies to ensure that the number of inspections is adequate.
2. Review the ERCB Drilling Rig Inspection Form and the related instruction guides to determine whether they are appropriate for individual rig inspections and also for determining whether the overall state of rigs in the Province is adequate.
3. Review whether the current basis used by the ERCB for classifying inspection deficiencies as ''serious'' is appropriate.
4. Consider and recommend a procedure whereby the results of ERCB rig inspections might best be communicated to the operators, the contractors, and the public.
5. Consider whether and in what manner the inspections by the operator and contractor might be incorporated into the system.
6. Consider whether a rework of inspection results for 1983, using the appropriate definition of ''serious'', is possible and appropriate.

The Board considers this to be an urgent matter and seeks your assistance. It has requested Mr. Remmer to complete the review and submit recommendations by 30 June 1984. That report will be a public document.

I would appreciate your advice as to the names of your representatives by 10 May 1984. Attached is a package of information that will be relevant to the committee.

Yours truly,

V. Millard
Chairman

VM/kl
Enclosures

ATTACHMENT II DRILLING RIG INSPECTION COMMITTEE

Canadian Petroleum Association
R. N. Powell - PanCanadian Petroleum Ltd.
L. N. Westermark - Esso Resources Canada Ltd.

Independent Petroleum Association of Canada
K. A. Caldwell - Dome Petroleum Ltd.
J. K. Farries - Farries Engineering (1977) Ltd.

Canadian Association of Oil Well Drilling Contractors
T. L. Doyle - Nabors Drilling Limited
J. A. Niedermaier - Badger Drilling Ltd.

Pembina Area Sour Gas Exposures Committee

K. R. Bissett - Gildex Ltd.

Energy Resources Conservation Board Staff

W. G. Remmer
E. F. May

ERCB
Energy Resources Conservation Board
640 5th Avenue SW
Calgary Alberta
Canada T2P 3G4

DRILLING & SERVICING OPERATIONS INSPECTION REPORT

DEVELOPMENT DEPARTMENT

GENERAL INFORMATION

CONTRACTOR NAME	NUMBER (1–5)	RIG NO (6–9)	RIG TYPE (10)	WELL I D (11): 1 LE LSD SEC TWP RGE W M 0
OPERATOR NAME	NUMBER (24–28)	INSPECTION TYPE (CIRCLE): PARTIAL P (29) / COMPLETE C (29)	AREA OFFICE (30–31)	INSPECTION DATE: YR. MO. DAY (32–37)
RIG MANAGER	CURRENT DEPTH (m)	PROJECT T D (m)	CASING SETTING DEPTH (m): SURFACE / INTERMEDIATE / PRODUCTION	RIG STATUS

MECHANICAL TESTS

DESCRIBE ALL TESTS CONDUCTED INCLUDING LOCATION OF EQUIPMENT AND CONTROLS

ACCUMULATOR	RECHARGE PUMP	BOP CONTROLS	BOP	TIME TO CLOSE	PRESSURE TEST (kPa) LOW	TIME	HIGH	TIME
		NO ON FLOOR						
MAKE	TIME min	TYPE	ANNULAR/HCR	s				
CAPACITY ℓ	N₂ BOTTLES	NO REMOTE	RAM	s		min		
WORKING PRESSURE kPa	NUMBER	TYPE	RAM	s		min		
PRECHARGE PRESSURE kPa	PRESSURE	DISTANCE m	RAM	s		min		
PRESSURE BEFORE kPa	HIGH kPa	HAND WHEELS	RAM	s		min		
PRESSURE AFTER kPa	LOW kPa		MANIFOLD					

INSPECTION RESULTS (INDICATE WITH AN 'X')

YES NO

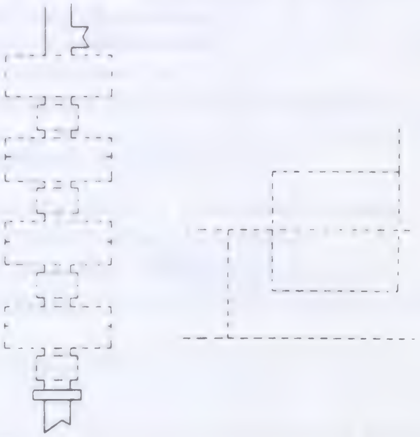
☐ ☐ 50 RIG APPEARS SATISFACTORY?

BOP SYSTEM

☐ ☐ 51 WITNESSED BOP PRESSURE TEST SATISFACTORY?
☐ ☐ 52 BOP TYPE RAM SIZE & PRESSURE RATING SAT?
☐ ☐ 53 BLEED OFF & KILL LINES APPEAR SATISFACTORY?
☐ ☐ 54 NON-STEEL HYDRAULIC LINES FIRE SHEATHED?
☐ ☐ 55 DRILL STRING VALVES READILY ACCESSIBLE?
☐ ☐ 56 EQUIPMENT ADEQUATELY HEATED?
☐ ☐ 57 BOP CONTROLS ADEQUATE?
☐ ☐ 58 BOP EQUIP WORKABLE & PROPERLY CONNECTED?
☐ ☐ 59 DRILL STRING PRESSURE AVAIL AT CHOKE CONTROL?
☐ ☐ 60 MUD-GAS SEPARATOR ADEQUATELY CONNECTED?
☐ ☐ 61 REQ'D CASING WEAR TESTS BEING PERFORMED?

TRAINING & PROCEDURES

☐ ☐ 63 DRILLER HAS P I T S KICK-CONTROL CERTIFICATE?
☐ ☐ 64 CREW BOP TRAINING APPEARS SATISFACTORY?
☐ ☐ 65 MUD VOL MEAS & HOLE FILL PROCEDURES SAT?
☐ ☐ 66 PERSON READILY AVAILABLE WITH SECOND LINE CERTIFICATE?



SPACING & RULES

☐ ☐ 75 WELL TO FLAME TYPE EQUIPMENT 25m?
☐ ☐ 76 END OF FLARE LINE 50m?
☐ ☐ 77 RUBBISH BURN PILE 50m?
☐ ☐ 78 CRUDE OIL STORAGE TANK 50m?
☐ ☐ 79 SMOKING RULES BEING OBSERVED 25m?
☐ ☐ 80 CONDENSATE RULES BEING OBSERVED?
☐ ☐ 81 D S T EQUIPMENT SATISFACTORY?

ENGINES

☐ ☐ 87 DIESEL ENGINE SHUT-OFFS STOP ALL ENGINES?
☐ ☐ 88 ENGINE EXHAUSTS SATISFACTORY?

RECORDS & OTHER

YES NO

☐ ☐ 99 FLUIDS PROPERLY CONTAINED?
☐ ☐ 100 WARNING SIGNS POSTED IN H_2S AREAS?
☐ ☐ 101 LICENSE POSTED? NUMBER ____________
☐ ☐ 102 REQUIRED DEVIATION SURVEYS RUN?
☐ ☐ 103 BOP PRESSURE TESTS RECORDED & TEST PROCEDURES SATISFACTORY?
☐ ☐ 104 DAILY MECHANICAL TESTS RECORDED?
☐ ☐ 105 WEEKLY DIESEL ENGINE TESTS RECORDED?

☐ ☐ **LETTER SENT BY AREA OFFICE?**

REMEDIAL ACTION REQUIRED ____________

AREA OFFICE	BOARD REPRESENTATIVE	INSPECTOR'S INITIALS (118 119)	CONTRACTOR REPRESENTATIVE	RIG DOWN TIME

ATTACHMENT IV SERIOUS RIG DEFICIENCIES

BOP TYPE, RAM SIZE, AND PRESSURE RATING

1 Using inadequate preventer

2 Improper pipe ram sizing while drilling

3 BOP pressure rating low

4 Casing Bowl improper pressure rating

5 Drilling spools improper pressure rating

6 Casing bowl valve improper pressure rating

BLEED OFF AND KILL LINES

1 Pressure gauge in manifold inaccurate (eg, out of calibration or range too large and no suitable backup)

2 Flanged fittings not used to connect spool to bleed off manifold

3 Check valve in kill line in backwards

4 Kill line or bleed-off line or manifold improper pressure ratings

5 Shock hose in kill line or bleed-off line improper pressure rating

6 Right angle bends not used on bleed-off line

7 Isolation valve not provided for manifold pressure gauge

8 Flare line not connected to manifold, secured, or staked down

9 Fluid 'T' in bleed-off line backwards

10 Bleed-off line not properly secured

DRILL STRING VALVES READILY ACCESSIBLE

1 Valve(s) not on location

2 Valve(s) not accessible

3 Stabbing valve closing handle not on location or inaccessible

4 Valve(s) not operating properly

5 Drill string and/or collar x-over sub not available or accessible

6 Inside BOP not accessible or not operative

EQUIPMENT ADEQUATELY HEATED

1 Blowout preventers seriously iced-up

2 Bleed-off and/or kill line valve(s) iced-up

3 Ice plug in bleed-off line

BOP CONTROLS

1 Accumulator precharge is too low to operate annular and hydraulic valve

2 Accumulator undersized

3 Full BOP controls not provided at or near driller's station

4 Remote BOP controls inadequate (eg, cannot close BOPs or open hydraulic valve from remote position)

5 Nitrogen bottles not provided

6 Nitrogen bottles not connected or improperly connected to accumulator

7 Accumulator pump failed to recharge accumulator

8 Annular or ram preventer seals leaking

9 Hydraulic hose(s) improper pressure rating

10 BOP control functions not clearly marked

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BOP EQUIPMENT WORKABLE AND PROPERLY CONNECTED

1 BOPs or hydraulic valve failed to operate from remote position

2 Annular or ram preventers or hydraulically-controlled valve failed to operate

DRILLER HAS PITS KICK CONTROL CERTIFICATE

1 Driller has never held a first line certificate

2 Person with second line certificate not readily available

CREW BOP TRAINING

1 Crew training inadequate

2 Crew drills not being performed

MUD VOL MEASUREMENTS AND HOLE FILLING PROCEDURES

1 Trip records not being completed

2 Monitoring device not working during drilling and tripping

3 Well control data not provided (eg, maximum back pressure to be held on casing)

4 Remote measurement device for tripping inaccurate (automated or measurement board)

5 Mud-tank level monitoring device not provided

6 Automated mud-tank level monitoring device not provided (Clases V and VI)

7 Warning device not provided at driller's position

8 Mud-level monitoring device improperly calibrated

9 Trip tank not provided

10 Fluid level dropped below 30 metres during tripping

DRILL STRING PRESSURE AVAILABLE AT CHOKE CONTROL

1 Remote drill pipe pressure not provided at manifold and/or remote drill pipe pressure gauge inaccurate

ATTACHMENT V EXAMPLE ANALYSIS
1983 ERCB INSPECTION RESULTS

Data Base

Wells drilled	4616
Active rigs	321
Unsatisfactory inspections	560
"Serious" unsatisfactory inspections*	316
"Serious" unsatisfactory inspection items*	435

TABLE 1 1983 INSPECTION COVERAGE AND RESULTS

Well Class	Wells Drilled	Inspections	Unsatisfactory Inspections
1	84	15	7
2	1369	214	79
3	2180	747	259
4	960	646	214
5	23	42	1
6	0	0	0
TOTAL	4616	1664	560

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* A "serious" unsatisfactory inspection or item is a rig deficiency subsequent to the initial drill out, which could contribute to an operational failure of the blowout prevention equipment or may restrict the crew's ability to safely detect, shut-in the well, and/or circulate out a well kick and maintain control of the well.

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TABLE II 1983 UNSATISFACTORY INSPECTIONS WITH "SERIOUS" DEFICIENCIES

Well Class	Number of Unsatisfactory ERCB Inspections	"Serious"	Per Cent "Serious"
1	7	2	29
2	79	61	77
3	259	145	56
4	214	108	50
5	1	0	0
6	0	0	0
TOTAL ALL CLASSES	560	316	56

TABLE III 1983 MOST FREQUENT SERIOUS INSPECTION ITEMS

Item		Per Cent of Total Serious Items
1	Mud-tank level monitoring device not operating	24
2	Bleed off and flare lines not staked down or secured	12
3	Trip records not completed	10
4	BOP remote controls did not function	6
5	Trip-tank level indicator not operating	5
6	Hydraulically-operated valve failed or control did not function	4
7	Bleed off line improperly designed (improper Tees or fluid turns)	4
8	Driller did not have first line certification	4
9	BOP failed to operate	3
10	Crew BOP drills not conducted	3
	TOTAL	75

TABLE IV MOST FREQUENT UNSATISFACTORY ITEMS IN THE NON-"SERIOUS" CATEGORY*

1 Diesel engine shut-offs not connected or failed to stop engines

2 Accumulator pre-charge low and/or accumulator failed to retain 8400 KPa after operating appropriate BOP equipment

3 Degasser improperly installed

4 Valve handle missing on bleed-off and kill line valves

5 Fire resistence sleeving inadequate on shock hoses and BOP hydraulic lines

6 Flare line does not terminate in flare pit

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* The items were not ranked by frequency of occurrence.

Lodgepole Inquiry
(ERCB Decision D 84-5)
BLOWOUT PREVENTION REVIEW COMMITTEE (BPRC)
Progress Report #2 - 17 October 1984

Background

The BPRC is a joint ERCB/Industry committee created to provide a detailed technical and economic review of a wide range of matters related to blowout prevention.

Meetings

The BPRC has held 10 meetings, including three meetings to deal specifically with the review of the Draft ID, since its inception in early June 1984.

Membership

- ERCB
  - Emile J. Morin, Chairman BPRC
    Manager, Development Department, ERCB
  - John R. Nichol, Secretary BPRC
    Senior Engineer, Development Department, ERCB
- CAODC
  - Peter C. Grigg, Vice President - Engineering
    Precision Drilling Limited
  - John A. Niedermaier, President and General Manager
    Badger Drilling Ltd.
  - T. L. (Terry) Doyle, President
    Nabors Drilling Limited
- CPA
  - Ed Bennett, Drilling Manager
    Esso Resources Canada Limited
  - J. R. (Jim) Tilbe, Manager - Drilling Division
    Shell Canada Resources Limited
- IPAC
  - Wilhelm (Bill) H. Sawotin, Manager - Western Drilling
    Canterra Energy Ltd.
  - D. M. (Dave) Huebner, General Manager, Drilling
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Activities

Terms of reference for the BPRC are contained in Appendices 6 and 7 of Decision Report D 84-5. These have been organized into "high" and "moderate" priority projects. The current status of these are as follows:

High Priority Projects

1) Critical Sour Wells (review of the draft interim directive)

The BPRC has held three meetings to discuss the views of their parent organizations on the adequacy and content of the draft ID. A draft of the committee's report to the ERCB was reviewed in detail at a meeting on 25 September 1984. The final draft of this report is currently underway and the report will be submitted by the 1 November 1984 deadline.

2) Training

The subcommittee, chaired by Peter Grigg of Precision Drilling, has held a total of six meetings to date. Dick Bissett, Bissett Resource Consultants, has joined this subcommittee as a representative of the Pembina Area Sour Gas Exposures Committee (PASGEC). This subcommittee has concentrated on the determination of specific areas of concern that could be alleviated through training. The next phase of their work will be to determine if the identified training needs are being met by existing training programs and if not, whether new or modified programs are required. The subcommittee will also address what personnel need what types of training.

3) Inspection and Enforcement

The subcommittee, chaired by Bill Remmer of the ERCB, has held a total of three meetings. This subcommittee has been looking into enforcement techniques, timing of inspections, qualification of ERCB and industry inspectors and blowout prevention equipment and casing testing requirements. The first draft of this subcommittee's report to the BPRC is currently underway.

4) Wellsite Supervision

The BPRC has deferred consideration of this matter until it has completed its review of the draft interim directive.

5) BOP Stack Equipment Standards

The subcommittee, chaired by Rick Lea of Shell has held a total of eight meetings. This subcommittee is conducting a review of BOP stack configurations, shear blind rams, mechanical specifications, material specifications, inspection and service requirements and auxillary equipment. The chief areas of concern at present are centred around the suitability of shear blind rams in sour service and the concensus respecting acceptable BOP stack configurations.

6) Drill Pipe, Manifolds and Auxillary Equipment

The subcommittee, chaired by Dan Belczewski of Gulf has held four meetings with the members of the main subcommittee and a number of task force committee meetings. The terms of reference for this subcommittee were accepted by the BPRC on 14 August 1984. This subcommittee has divided its extensive workload amongst the following seven task forces: drillpipe metallurgy and design, poorboy degassers, manifold redundancy, choke and kill line metallurgy and piping, pressure gauges, shop servicing and testing of auxillary equipment and inside BOPs. All of the task forces are actively pursuing their areas of concern and the main subcommittee is reviewing their progress and dealing with problems on an as-required basis.

7) Detection and Monitoring

The subcommittee, chaired by Helmut Rath of PanCanadian, has held three meetings of the main subcommittee and a number of meetings of the three task forces that have been established. The terms of reference for this subcommittee were accepted by the BPRC on 14 August 1984. This subcommittee has separated its mandate into the following three working groups: kick monitoring, techniques for surface monitoring of hydrogen sulphide and techniques for subsurface monitoring of hydrogen sulphide. All of the working groups are actively pursuing their respective areas of concern.

8) Alberta Code of Practice for Drilling

An outline of the concepts being considered by the BPRC has been reviewed by the ERCB and the detailed review of this matter has been put on hold until the Lodgepole Inquiry Phase 1 report has been released and the findings of the various BPRC subcommittees are available.

Moderate Priority Projects

9) Drilling Information Exchange

The availability of and access to drilling information has been reviewed by the BPRC and a summary report outlining the findings is being developed for presentation to the ERCB.

10) Well Planning

The majority of the items included under well planning are subjects that will be addressed by the "Alberta Code of Practice for Drilling" and consequently, the only other area of concern was the free access to geologic information as it relates to potential drilling problems. The BPRC has discussed this aspect and a report is being developed for presentation to the ERCB.

11) Mud System Design

The BPRC has completed a preliminary review of this subject and it believes that a subcommittee will have to be formed to review this matter in the kind of detail that will be required. However, as this subject area ties in very closely with the "Alberta Code of Practice for Drilling", further review has been deferred until the discussion on the code is resumed.

12) Winter Drilling

The BPRC believes that this subject should be included under the "Alberta Code of Practice for Drilling" and consequently consideration of this item has also been deferred.

13) Blowout Equipment Co-operative

The BPRC has had discussions on the value of a central equipment storage site, including specific discussion respecting the use of existing CPA inventory of equipment in Edmonton. Ready access to rental equipment, the unique aspects of each blowout and the desire of most well control companies to use their own equipment would seem to indicate that there is very little need to establish a blowout equipment co-operative. A report to the ERCB is currently being prepared.

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(297-8169)

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DEC 1 2 [illegible]

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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ESSO RESOURCES CANADA LIMITED QUIRK CREEK GAS PROCESSING PLANT

Decision D 84-6
Application 830698

1 INTRODUCTION AND BACKGROUND

Esso Resources Canada Limited (Esso) applied in 1981, pursuant to section 38 of The Oil and Gas Conservation Act[1], for approval to utilize spare plant capacity to process sour gas reserves from the Moose and Whiskey fields at its Quirk Creek gas processing plant located in the south half of section 4, township 21, range 4, west of the 5th meridian. However, the Board in Decision 82-12 said it was not prepared to approve the application of Esso because applications by Shell Canada Resources Limited (Shell) for the pipeline system necessary to transport the Moose and Whiskey gas reserves to the Quirk Creek gas plant had been denied.

After Shell completed a risk assessment of the proposed Moose pipeline and related facilities, it applied to have the Board rescind or vary its prior order so as to permit the construction of the pipelines and related facilities. Following a public hearing to consider the new evidence, the Board approved the application subject to certain conditions. Esso then applied, pursuant to section 42 of the Energy Resources Conservation Act, for the Board to reconsider Decision 82-12 with the intent of gaining approval to process sour gas reserves from the Moose and Whiskey fields at its Quirk Creek plant.

The approved maximum raw gas inlet rate for the Quirk Creek plant of 2.536 million cubic metres per day (10^6 m^3/d) would not be increased. A maximum of 1.928 x 10^6 m^3/d of sales gas, 620 m^3/d of liquefied petroleum gases (LPG) mix, and 295 tonnes per day (t/d) of sulphur would continue to be recovered.

Esso proposed to increase the Quirk Creek plant sulphur recovery efficiency from the currently-approved minimum quarterly level of 95.5 per cent to 96.5 per cent (95.8 per cent to 96.8 per cent on a normal operating basis). By improving process control with no major physical changes to the plant, Esso would decrease the maximum permitted sulphur dioxide (SO_2) emission rate from 27.6 t/d (13.8 t/d of sulphur) to 22.6 t/d (11.3 t/d of sulphur). The SO_2 would be emitted to the atmosphere through the existing 107-metre incinerator stack.

Hearing of the application commenced on 24 October 1983 and resumed on 27 October, at which time a number of procedural aspects were announced by the Board and the hearing was then adjourned to allow for the filing of additional evidence. Pursuant to filing of evidence by the applicant and interveners, the hearing resumed on 16 January 1984 and continued through 17, 19, 20, and 25 January 1984. V. Millard, N. Strom, P.Eng., and R. G. Evans, P.Eng., comprised the sitting panel.

2 ISSUES

Having regard for the evidence presented at the previous hearing pertaining to operations at the Quirk Creek plant, the Board believes that certain conclusions should be reached prior to addressing the essential issues now before it. These are in regard to the environmental impact and additional gas recovery from the Quirk Creek Field due to the Quirk Creek plant life extension.

Esso submitted additional evidence at the current proceeding to show that no discernible adverse local environmental impacts had occurred since the completion of the previous hearing two years ago. Thus, with future operations planned to reduce SO_2 emissions from the current maximum permitted level of 27.6 t/d to 22.6 t/d, it was satisfied that future operations would meet and exceed the standards and would not impose discernible environmental impacts.

Addressing the questions of SO_2 emission rate and cumulative sulphur emissions, Z. Hanen and Rumsey Ranches (Hanen) implied that it would be extremely difficult to measure the effects of SO_2 emissions over a short time frame. However, Hanen held to the position that the cumulative impact of the additional sulphur emissions as a result of extended plant life would necessarily have some long-term impact even though it could not be easily measured. The Square Butte Community Association observed that the plant was a modern, well-run facility with a very acceptable environmental management record.

The Board is satisfied that the Quirk Creek plant is entirely capable of meeting current and future local environmental standards in accordance with the applied-for scheme of operations. In this light, the Board does not regard local environmental impact to be an issue, but, of course, the broader environmental question implicit in IL 80-24[2] would have to be addressed.

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[1] Now section 26 of the Oil and Gas Conservation Act.

[2] Energy Resources Conservation Board, 1980. **Sulphur Recovery Guidelines - Gas Processing Operations.** ERCB Informational Letter IL 80-24. Calgary, Alberta.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Resources Canada Limited (Esso) D. G. Hart, Q.C. R. C. Pittman	Dr. R. G. Auld, P.Eng. E. R. Caldwell, P.Eng. K. Luedtke, P.Eng. B. Toner
Shell Canada Resources Limited (Shell) D. O. Sabey, Q.C. A.P.G. Walker	
Z. Hanen and Rumsey Ranches (Hanen) J. D. Rooke	D. G. Goar, P.E. T. O. Arrington, P.E. both of Goar, Arrington & Associates, Inc. H. P. Simon of Foster Research
Square Butte Community Association M. J. Visser	M. J. Visser
Waste Heat Products Ltd. G. N. Gillund, P.Eng.	G. N. Gillund, P.Eng.
Alberta Environment C. S. Liu O. Dick	
Energy Resources Conservation Board staff D. A. Holgate W. J. Schnitzler, P.Eng. L. D. Holizki, P.Eng. K. Johnston L. S. Fillion, C.E.T. V. H. Seaman	

On the matter of resource recovery, Esso indicated that the operating life of the plant would end in 1997 if no gas reserves other than from the current Quirk Creek Field were connected to supply the plant. However, with Moose and Whiskey gas being brought in, the plant life would be extended to 2015. This would permit continued operation of the Quirk Creek Field beyond 1997, resulting in additional raw gas recovery of 1200 x 10^6 m^3 from the Quirk Creek Field. This benefit, plus the added advantage of utilizing the substantial and increasing spare plant capacity at Quirk Creek, confirms the Board's previous conclusions in Decision 82-12 respecting the advantage of bringing Moose and Whiskey gas to the Quirk Creek plant. The Board believes that all participants in the proceeding were essentially in agreement that the proposed project would offer these economic and resource recovery benefits.

In view of the foregoing conclusions, the Board believes that the major issue is that of establishing the appropriate sulphur recovery efficiency for the proposed project. The Board proposes to evaluate this issue by addressing the three sequential questions posed in the following section.

3 REQUIRED SULPHUR RECOVERY EFFICIENCY

The Board believes that the basic questions respecting sulphur recovery efficiency are:

- Would a new plant installed to process only Moose reserves be required to meet a sulphur recovery efficiency consistent with IL 80-24?
- Would the proposed 96.5 per cent design as submitted by Esso ensure that the Moose and Whiskey gas would continue to be processed in accordance with IL 80-24 throughout the life of the project?

- Would the processing of Moose and Whiskey reserves at Quirk Creek require such special capital or operating expenditures as to warrant deviating from the guidelines?

3.1 Would a New Plant Installed to Process Only Moose[3] Reserves be Required to Maintain a Sulphur Recovery Efficiency Consistent with IL 80-24?

Based on evidence presented at the hearing, the Board assumed that a plant site would not be permitted in Kananaskis Country, that gathering and development costs[4] would be some $56 million, and that plant costs might be as high as $50 million[5] including tail gas clean-up facilities.

Based on these assumptions, the Board has concluded that the discounted cash flow rate of return after taxes, for a separate new plant at an acceptable location, would be in excess of 19 per cent. While perhaps not the most attractive investment, the Board concludes that a new plant to process Moose gas would be economically viable and that the operator would be required to meet the minimum provisions of IL 80-24. Based on the Board's estimate that the plant would have a sulphur inlet of some 150 t/d, the required sulphur recovery efficiency would be 97.5 per cent on a normal operating basis[6].

3.2 Would the Proposed 96.5 Per Cent Design as Submitted by Esso Ensure that the Moose and Whiskey Reserves Continue to be Processed in Accordance with IL 80-24 Throughout the Life of the Project?

Esso previously submitted that its proposed 96.5 per cent sulphur recovery efficiency reflected an approximate equal weighting between Quirk reserves at the current sulphur recovery efficiency and Moose and Whiskey reserves at a sulphur recovery efficiency consistent with IL 80-24. Esso's primary position was that the proposed 96.5 per cent efficiency could be achieved with relatively small capital and operating cost effects. Also, since average daily emissions would continue to be lower than the maximum approved limits, Esso was confident that its proposal would not cause environmental damage. Thus, Esso's proposal did not appear to be derived directly from a consideration of IL 80-24.

Esso stated that a quarterly sulphur recovery efficiency of up to 96.7 per cent could be achieved by implementing any one of a number of sulphur plant reconfigurations, but confirmed that a tail gas clean-up unit (TGCU) would be needed if a sulphur recovery efficiency of greater than 96.7 per cent were required.

Hanen stated that Esso's proposal of 96.5 per cent quarterly sulphur recovery did not represent a true weighted average between old and new gas. Hanen calculated that, based on the revised raw gas nominations for the Quirk Creek, Moose, and Whiskey reserves to the year 2015 compared to the raw gas nomination for only the Quirk Creek reserves to 1997, a weighted average of 96.9 per cent quarterly sulphur recovery would be needed to ensure all the new gas was being processed in accordance with IL 80-24.

In attempting to address this question, the Board paid particular attention to the raw gas deliverability forecast and sulphur production forecasts as filed by Esso. In these forecasts the raw gas input from Moose and Whiskey reserves exceeds that from the Quirk Creek Field after only three years of operation. Similarly, the sulphur production forecast indicates that the sulphur product from Moose and Whiskey reserves would exceed that from the Quirk Creek Field as early as the second year of operation and for much of the plant operating life would be three or more times greater. From these data it is evident that, under the Esso proposal, the Moose and Whiskey raw gas would not be processed in a manner which would meet the requirements of IL 80-24. Thus, even considering the project on a weighted raw gas throughput basis, Esso's proposal is in effect a request for exemption from strict adherence to the provisions of IL 80-24.

3.3 Would the Processing of Moose and Whiskey Reserves at Quirk Creek Require Such Special Capital or Operating Expenditures as to Warrant Deviating from the Guidelines?

Esso planned to achieve a level of 96.5 per cent quarterly sulphur recovery by certain modifications in controls and more frequent catalyst change-out. Esso stated that additional capital costs at the Quirk Creek plant would be in the order of $6.0 million to facilitate processing the

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[3] The Board notes from evidence submitted at the previous hearing that production of Whiskey gas was not economic except in conjunction with the Moose gas as outlined in the proposed scheme. Therefore, in addressing this particular question, the Whiskey reserves have been excluded.

[4] Based on evidence submitted by Shell at the earlier Moose proceeding. This cost would provide for transportation of the raw gas to the Jumping Pound plant site.

[5] A conservatively high estimate reflecting evidence submitted by Shell and by Goar, Arrington & Associates, Inc.

[6] IL 80-24 indicates the sulphur recovery efficiency that should apply under normal operating conditions. It also specifies that the minimum sulphur recovery efficiency determined for any quarterly period may be as much as 0.3 per cent lower than the normal requirement and still be considered to be within the terms of the approval.

Moose and Whiskey gas and to increase quarterly sulphur recovery to 96.5 per cent. Esso submitted that if a higher sulphur recovery efficiency were required, the project would have to be seriously re-evaluated. The basis for the re-evaluation would be the incremental revenues from the extended life of the Quirk Creek Field plus the processing fee accruing from the Moose and Whiskey gas, versus the incremental capital and operating costs required for the expansion. While Esso did not submit any evidence with respect to incremental revenues, it stated that capital costs for a Claus plant reconfiguration could range from \$0.5 million to \$3.7 million with operating costs of about \$0.1 million per year, while a sub-dewpoint TGCU could range from \$4.3 million to \$13.0 million with operating costs of about \$0.4 million per year. Esso testified that the plant site configuration would not present serious obstacles to installation of a TGCU.

On the basis of evidence prepared by Foster Research and Goar, Arrington & Associates Inc., Hanen submitted that the imposition of a higher sulphur recovery requirement would not seriously jeopardize the economic viability of the proposed scheme and also noted that it would be possible to retrofit the plant with a TGCU without encountering serious difficulties. On the basis of an analysis extending to the year 2005, Hanen concluded that the project's real after-tax rate of return without a TGCU would be about 30 per cent; this would decline to about 26.5 per cent with a TGCU. The analysis further indicated that with a discount rate of 11 per cent, the project's discounted net revenues (after taxes) would amount to \$98.4 million (without a TGCU) or \$83.0 million (with a TGCU). In her revenue calculations, Hanen included all the revenue attributable to production of the Moose and Whiskey fields, as well as that from the Quirk Creek Field after the year 1985. The analysis assumed that capital costs for a TGCU would be about \$5.3 million and operating costs for the unit would be about \$1.3 million per year, in constant 1985 dollars.

The Board agrees with the participants in the hearing that installation of a TGCU would result in both capital and operating costs that would impact negatively on the economic return of the project. That situation is, however, not unique to the Quirk Creek proposal but is, in fact, inherent in the sulphur recovery rates required under IL 80-24.

In its analysis of the TGCU which would be required for Quirk Creek, the Board considered only the incremental costs and incremental revenues that would apply if the Moose and Whiskey gas were processed at that plant. Thus, the revenue accruing to the Quirk Creek plant under the existing plan of operations and assuming that Moose and Whiskey gas is not processed at the plant was excluded. While the Board has some reservations about the product price forecasts used by Foster Research, it doubts that a more conservative forecast would materially affect the results and therefore the Foster Research price forecast was used for the Board's analysis.

The Board estimated Moose and Whiskey gathering system and development costs[7] to be \$53 million, basic plant modification costs[8] to be \$5 million, and TGCU costs[9] to be \$9 million. The additional operating costs for the new gas were based on Shell's earlier evidence prorated to field and gathering facilities, and escalated to 1985, the assumed first year of production.

The results of the Board's economic analysis indicates that the modified 3-stage Claus operation would yield an incremental discounted cash flow rate of return (after tax) of about 29 per cent. With the added cost burden of a TGCU, the incremental rate of return would decline to about 26 per cent.

The Board believes that it is significant that the proposal to process the Moose and Whiskey reserves at Quirk Creek provides a much more attractive rate of return, even with the installation of a TGCU, than would be obtained from a new plant. The reason for the improvement stems from the several economic benefits obtained by using existing facilities rather than constructing new facilities. Furthermore, economic benefits accrue to the existing scheme by permitting more efficient operations. The major benefits are:

- Investment at the Quirk Creek gas plant, even with a TGCU, is substantially less than required for a new plant (\$14 million vs \$50 million).
- Operating costs per unit of marketable gas for the remaining life of the plant, that is to 1997, are reduced by up to 50 per cent in some years because of increased raw gas deliveries.
- The recovery of Quirk Creek gas is increased by some 1200 x 10^6 m^3.

4 SUMMARY

The Board is satisfied that if an application had been filed to process Moose gas at a new plant, any approval issued would have included a requirement for sulphur recovery consistent with IL 80-24, that is, a recovery efficiency of some 97.5 per cent under normal operating conditions. However, as indicated in Decision 82-12, the Board believes the proposal to process Moose and Whiskey reserves at Quirk Creek to be a superior alternative since it allows increased recovery of Quirk Creek reserves as well as providing other significant benefits. The Board sees no reason why the processing of Moose, Whiskey, and Quirk Creek reserves at the Quirk Creek plant should not be subject to at least the same recovery requirements as would apply if the Moose reserves were processed at a new facility. Installation of a TGCU would provide an additional benefit since it would permit increased recovery of sulphur from the Quirk Creek reserves.

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[7] Based on evidence submitted by Shell at the earlier Moose proceeding.

[8] Based on Esso's original estimate of \$6 million adjusted to reflect Esso's subsequent statement that certain modifications were no longer proposed.

[9] Approximate mid-range of estimates submitted by Esso for sub-dewpoint TGCU.

The Board recognizes that a 3-stage Claus plant could be designed and operated so as to recover in the range of 96 to 97 per cent sulphur recovery on a normal operating basis. Anything beyond that level leads to consideration of an additional stage of processing, ie, a unit designed to recover as much as practical of the remaining 3 to 4 per cent of the original sulphur. Although this tail gas contains only dilute concentrations of sulphur compounds, the TGCU would still usually achieve over 50 per cent sulphur removal. The combined effect for 3-stage Claus plus TGCU is therefore usually 98 per cent or more sulphur recovery efficiency.

It is evident that to meet or exceed the 97.5 per cent sulphur recovery efficiency at the Quirk Creek plant will require the installation of a fourth process stage, this being a TGCU. The specific recovery level attainable would be dependent upon the TGCU selected as well as the operating experience. The Board believes that the establishment of the specific recovery level should be deferred until after the process has been selected and operating experience obtained. Nevertheless, the Board holds to the position that in no event should the recovery efficiency be less than 97.5 per cent on a normal operating basis.

The Board has decided to require the installation of tail gas clean-up facilities not because of possible local environmental impacts but rather because of the broad environmental implications inherent in IL 80-24. The Board recognizes that the processing of Moose and Whiskey reserves has been delayed for a long period and having regard for its finding respecting local environmental impacts, it sees no reason why arrangements should not proceed to tie-in and process those reserves at the Quirk Creek plant prior to the completion of the installation of tail gas clean-up facilities. The processing of the Moose and Whiskey reserves would, of course, be subject to the conditions specified above, as well as completion of the construction within a reasonable period. The Board concludes therefore that the Moose and Whiskey reserves may, for a limited period of time, be processed at the Quirk Creek plant, subject to the current sulphur recovery requirements. Beyond that period, the processing would be subject to a recovery efficiency of not less than 97.5 per cent on a normal operating basis. The Board believes that this interim arrangement should not exceed two years, subject to any extension the Board may grant by stipulation following application by Esso.

5 DECISION

The Board is prepared to approve the application on the following conditions:

- That Esso select a tail gas clean-up unit capable of ensuring not less than 97.5 per cent sulphur recovery on a normal operating basis.
- That prior to commencing construction of the modifications to the plant, Esso obtain Board approval of the tail gas clean-up unit chosen.
- That a sulphur recovery efficiency of not less than 97.5 per cent will apply at a date prescribed by the Board but not more than two years from the date of Amendment of Approval No. 2944 authorizing the processing of the Moose gas at the plant, subject to any stipulation of a later date by the Board.

DATED at Calgary, Alberta, on 17 April 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R G Evans

R. G. Evans, P.Eng.
Acting Board Member

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

CANTERRA ENERGY LTD.
SOUR GAS PIPELINE
FUEL GAS PIPELINE
CALGARY AREA

Decision D 84-7
Applications 831021 and 831022

1 INTRODUCTION

1.1 The Applications

Canterra Energy Ltd. (Canterra) applied, pursuant to Part 4 of the Pipeline Act, for permits to construct pipelines to gather sour gas from and deliver fuel gas to wells in the Okotoks Field. The raw gas would be processed at the Canterra Okotoks gas plant. Figure 1 shows the well locations, Canterra-proposed pipeline routes (preferred and alternative), and certain geographic and other features of the area. Intervener-proposed routes are shown on Figure 2.

Application 831021 is to construct approximately 11.30 kilometres (km) or alternatively 10.25 km of 60.3-millimetre (mm) outside diameter (OD) fuel gas pipeline from legal subdivision 10, section 2, township 22, range 29, west of the 4th meridian (10-2), to well sites located at 10-13-22-29 W4M (10-13), 11-24-22-29 W4M (11-24), and 10-20-22-28 W4M (10-20).

Application 831022 is to construct approximately 11.15 km or alternatively 10.95 km of 60.3-, 88.9-, and 168.3-mm OD sour gas pipeline from the 10-20 and 10-13 wells to connect to an existing pipeline at 10-2-22-29 W4M.

1.2 The Interventions

1.2.1 B. Lammle and M. Lammle (the Lammles) owners of the SE 1/4 11-22-29 W4M

The Lammles opposed Canterra's preferred route because of safety, environmental, and land development concerns. They believed the safety of more people in the Bow River valley would be at risk if the Canterra preferred route was approved instead of an alternative route. They supported the routing of the pipelines along existing linear disturbances such as property boundaries, and contended that significantly more tree and brush clearing would be required with Canterra's preferred river crossing alignment. Potential future building sites were identified in close proximity to Canterra's preferred route (see Figure 2).

1.2.2 L. McKeag owner of a portion of the SE 1/4 20-22-28 W4M

Mr. McKeag stated a concern about land devaluation and safety.

1.2.3 A. Moeller owner of the NE 1/4 20-22-28 W4M

Mr. Moeller appeared at the hearing but did not express any views about the proposed pipelines.

1.2.4 F. J. Ollerenshaw owner of section 23-22-29 W4M and the W 1/2 24-22-29 W4M

Mr. Ollerenshaw stated that, "if any approvals granted by the Board were suitably conditioned to recognize and protect the interests of the surface owners and to incorporate the most up to date safety precautions . . . (he) . . . would not be opposed to the construction of the Canterra pipelines." Mr. Ollerenshaw's main concern was the effect that the existing wells and proposed pipelines would have on the timing of future urban development of his property. He requested that the Board limit the time period over which resource development could take place and clarify the extent of any sour gas constraints in the area so that his lands could be included in the City of Calgary's land annexation study. Further, he requested that the Board require Canterra to install sufficient emergency shut-down (ESD) valves to limit the potential hydrogen sulphide (H_2S) release volumes from the proposed pipeline between 11-24 and 10-13 so that it would be a Level 1 sour gas facility as set out in ERCB Interim Directive ID 81-3[1]. He also suggested that Canterra should be required to commence construction of the pipelines within one year.

1.2.5 D. Pearson and R. Pearson (the Pearsons) owners of section 17-22-28 W4M

The Pearsons expressed concern about the effect the proposed pipelines would have on area land values in relation to future urban development potential and supported conditioning the pipeline approvals to limit the resource recovery time to a maximum of 15 years. They were concerned about their safety and the safety of their cattle in the event of a well blowout or pipeline rupture. Other conditions recommended by the Pearsons included: accelerated production rates, immediate tie-in of the 11-24 well, restricting the drilling of future wells or tie-in of future pipelines in the area, and resident notification of emergency response and procedure plans.

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[1] Energy Resources Conservation Board, 1981. *Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments*. Interim Directive ID 81-3. Calgary, Alberta.

1.2.6 R. Shields and V. Shields (the Shields) SW 1/4 12-22-29 W4M

The Shields initially objected to both Canterra proposed routes and noted that a previous study of the area concluded that "for the construction phase the northern routes (to the Petrogas Balzac gas plant) are preferable". To support their position the Shields cited Bow River slope instabilities, Bow River crossing construction timing constraints (fish spawning), crossing of environmentally sensitive terrain, and impacts to developable land. Alternatively, if the gas could not be transported to the Balzac gas plant, the Shields indicated that Canterra's preferred route would be acceptable. They opposed the Canterra alternative route because of its proximity to future building sites, safety concerns (from a Level 2 sour gas facility), and impacts to developable land.

The Shields suggested several alternative routes that would be acceptable to them (see section 4 and Figure 2).

1.2.7 C. G. Soutzo and A. G. Soutzo (the Soutzos) owners of portions of sections 3, 4, 8, 9, 10, 11, 12, 13, 14, and 15 in 22-29 W4M

The Soutzos generally opposed the proposed pipelines and stated that they would have an adverse effect on their ranching operations, would inhibit subdivision of their lands and preclude consideration of the lands for annexation by the City of Calgary. The Soutzos said that Canterra's preferred Bow River crossing (in comparison to the alternative river crossing) would be unsafe because of bank steepness and slope instability. It would also be unacceptable because more active river channels would be crossed and there would be more environmental impacts with that crossing location. Additionally, access to the river crossing location for maintenance related operations would be poor.

They contended that the pipelines should follow existing linear disturbances where possible and the routes be selected to minimize the effects to lands with potential for urban encroachment.

The Soutzos supported time limited resource development.

1.2.8 K. Uragi
owner of land in the N 1/2 12-22-29 W4M
south of the Bow River and
the NW 1/4 11-22-29 W4M

Mr. Uragi supported Canterra's preferred route because it would have less impacts to his property than Canterra's alternative route.

1.2.9 Workman Group
owners of acreage parcels
in the SE 1/4 20-22-28 W4M

The Workman Group was concerned about resident safety and evacuation procedures, the potential for future surface facilities that may emit odours, and the tie-in of other Chestermere Lake area reserves to the proposed pipeline.

1.2.10 Committee for Toxic Pollutant Controls (CTPC)

The CTPC took the position that even though the wells were proposed for tie-in to the Canterra Okotoks gas plant, the gas in question should be processed for at least the sulphur recovery level that would occur if the gas were processed at the proposed Canadian Occidental Mazeppa gas plant.

1.2.11 City of Calgary (the City)

The City answered questions regarding future expansion of the city as well as its urban planning policies. It supported the Canterra applications in principle because the pipelines would allow recovery of gas reserves underlying lands with urban development potential.

1.3 The Hearing

G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., heard the applications at a public hearing on 15, 16, and 17 February 1984, in Calgary, Alberta.

The appendix lists those who appeared at the hearing.

1.4 The Background

In June 1979 and January and March 1980, the Board considered pipeline applications by Amerada Minerals Corporation of Canada Ltd. (Amerada) to connect the 10-13, 11-24, 10-20, and 6-29-22-28 W4M wells to the existing Texasgulf Inc. (now Canterra) gathering system and return fuel gas to those well sites.

In Decision 80-6 the Board concluded pipelines were necessary to recover the reserves in the area but that the approvals should be for a limited time period to allow for future review of resource development in the area given the likelihood of encroachment by the City. The Board conditioned its approval of the pipelines to allow for review after 12 years because land-use conflicts could develop during the estimated 20-25 year life of the proposed pipelines. It also required Amerada to provide other information regarding safe operation of its proposed facilities north of the Bow River.

The Board approved a route similar to Canterra's current alternative route but Amerada did not construct the pipelines.

In March 1983, the Board held an inquiry to investigate how potential conflicts between the development of the sour gas reserves in the Okotoks area and residential development might be minimized. In Inquiry Report D 83-12, the Board indicated that for lands east of the city boundary where "... land-use conflicts are near-term, ... it would be necessary to establish the period under which exploration and development would be permitted."

In October 1983, Canterra filed the subject applications for the proposed pipelines stating that it had recently acquired the reserves in question from Amerada and PanCanadian Petroleum Ltd. (PanCanadian).

2 ISSUES

The Board considers the issues respecting the applications to be:

- the purpose and necessity of the proposed pipelines, including the appropriateness of a limit to the time for which the approval would be effective,
- the route of the proposed pipelines and the need for valves to limit the maximum potential sour gas release volumes,
- the need for special permit conditions if the applications are approved, and
- pipeline design.

Also, because there was considerable discussion about sour gas related land-use planning constraints in the general area, the Board will comment on that matter in this report.

3 PURPOSE AND NECESSITY AND THE APPROPRIATENESS OF A LIMITED TIME PERIOD FOR ANY APPROVAL

3.1 Canterra's Views

Canterra stated it had conditionally purchased the Amerada and PanCanadian Wabamun B and Rundle A gas reserves underlying lands north of the Bow River in the Okotoks Field. The purchase is subject to Canterra receiving permits to construct pipelines to connect the gas reserves to its gathering system. Canterra said that the purchase included an existing 25-year, reserves-based TransCanada PipeLine Limited contract for the PanCanadian reserves, as well as a similar contract currently being negotiated by Amerada for its reserves.

The applications are for facilities to allow production of the reserves purchased by Canterra. It stated that although 225 thousand cubic metres per day (10^3 m^3/d) raw gas inlet process capacity was available at its Okotoks gas plant, it would initially only be able to sell about 85 x 10^3 m^3/d because of gas market constraints.

Canterra estimated the total remaining marketable Wabamun reserves north of the Bow River to be about 845 million (10^6) m^3 with approximately 422 x 10^6 m^3 underlying sections 13 and 24 (10-13 and 11-24 wells). Canterra said that these reserves are being slowly drained by wells to the south but estimated that the ultimate recovery of them would only be about 170 x 10^6 m^3 (20 per cent of 845 x 10^6 m^3 if no wells north of the river were produced.

Canterra proposed to initially produce only the 10-13 well to deplete the Wabamun reserves because it can adequately supply the contract volumes. The 11-24 well would be tied in when the 10-13 well could no longer meet the contract. Canterra estimated that if the 11-24 was not produced, the 10-13 well could recover about 50 per cent of the reserves north of the river, including about 40 per cent of the reserves under section 24.

Canterra stated that experience gained by producing the 10-13 and 11-24 wells could indicate that the recoverable Wabamun reserves are higher than its current estimate.

Canterra estimated the marketable Rundle reserves that could be recovered by the 10-20 well to be about 422 x 10^6 m^3. It suggested a possibility that the Rundle A Pool extends to the north and that some gas might be recovered from the section to the north.

Canterra indicated that although the economic payout of the proposed facilities would be in the order of 12 years, it preferred not to have any resource development time constraints imposed. It stated that reserve recovery would take about 20-25 years even if there were no gas marketing constraints or other restrictions in that time. Canterra questioned the likelihood of urban development of lands in proximity to its proposed pipeline within that time period, having regard for the extent of undeveloped lands within the current city limits and other developable lands available for annexation.

When questioned about the possibility of cross-dedication of reserves from other contracts and/or unitization with lands to the south to allow for accelerated depletion of the reserves, Canterra said that those alternatives would entail numerous complex agreements and would be very difficult if not impossible to implement.

3.2 Interveners' Views

Mr. Ollerenshaw did not dispute the need for the pipelines but suggested that the reserves north of the Bow River, particularly the Wabamun reserves, should be expeditiously depleted with a minimum of impacts to the surface owner. He stated that his property is suitable for urban development but has been excluded from consideration for future annexation because of a "sour gas constraint" resulting from discussions between the ERCB and the City regarding the potential for sour gas development.

Mr. Ollerenshaw indicated that the property will continue to be excluded from consideration for annexation unless it can definitively be shown as available for urban development some time within 30 years. Mr. Ollerenshaw's planning consultant estimated that urban development of the area might occur in 10-20 years if there were no sour gas facilities in the area.

Mr. Ollerenshaw's reservoir consultant noted the Board's 1980 estimate of $225 \times 10^6 m^3$ of marketable Wabamun reserves underlying sections 13 and 24 as reported in Decision 80-6, and estimated that those reserves could be depleted in about 13-15 years if there were no gas processing plant or gas market constraints. He agreed with Canterra that if the reserves under sections 13 and 24 were in fact $422 \times 10^6 m^3$, then the recovery time could be 20-25 years.

Mr. Ollerenshaw contended that if resource development of the area was limited to a future set time period, his lands could be included in the annexation study being conducted by the City. He suggested that the Wabamun reserves be connected as soon as possible and that production be limited to 8 years (the remainder of the 12-year time period set in Decision 80-6) with a provision for a 5-year extension upon application. He said the 13-year period would provide incentive to deplete the reserves faster. He further suggested that continued resource development after 13 years should be at the discretion of the surface owner and the City.

The Pearsons contended that Canterra should be limited to 10 years to recover its reserves at which time another hearing would be held to review the extent of any land-use conflicts and the possibility of allowing resource recovery to continue for another 5 years. They stated that regardless of the extent of reserve recovery, the wells and pipelines should be abandoned after the total of 15 years.

The Shields and Soutzos supported the concept of a limited time period for resource development.

The remaining interveners did not question the necessity for the pipeline to connect the 10-20 and 10-13 wells to the existing gathering system.

3.3 Board's Views

The Board has reviewed its estimates of Wabamun and Rundle reserves north of the Bow River. It now estimates the remaining Wabamun reserves to be approximately $817 \times 10^6 m^3$ of which about $333 \times 10^6 m^3$ underlie sections 13 and 24. This is only slightly less than the total estimate by Canterra but is considerably lower with respect to sections 13 and 24.

The Board estimates the marketable Rundle reserves to be about $272 \times 10^6 m^3$ as compared to the $422 \times 10^6 m^3$ estimate of Canterra.

In Decision 80-6, the Board acknowledged that drainage of the subject Wabamun reserves was taking place by wells south of the river but believed that significant amounts of reserves would not be recovered if the wells north of the river were not produced. Its views have not changed in this respect. While its estimate of the possible recovery from wells south of the river is slightly higher than Canterra's, the Board nevertheless believes the reserves ought to be recovered expeditiously. It further believes that the efficient and expeditious recovery of the Wabamun reserves should involve the production of the 11-24 well along with the 10-13 well. Section 5.2.3 discusses the testing and tie-in of the 11-24 well.

The Rundle reserves underlying the 10-20 well cannot be recovered unless the well is put on production. Additionally, processing capacity for both the Wabamum and Rundle gas is available at the Canterra Okotoks gas plant.

Given the incremental reserves that can be recovered and the availability of processing capacity, the Board is satisfied that pipelines are required to connect the wells north of the river to the Okotoks gas processing plant.

The Board heard evidence regarding the potential for urban development of lands in the project area. The City currently excludes these lands from annexation studies because of the potential for sour gas development in the area. While the Board believes that urban development of the area might take place within the 30-year annexation study timeframe if there was no sour gas constraint, it is uncertain from the evidence presented at the hearing as to when encroachment would actually occur. However, because the potential for resource and urban development conflict exists, the Board believes efforts should be made to accelerate production rates and recover most of the reserves in as short a period as practical. Ways suggested at the hearing included reserve cross-dedication between gas contracts, or unitization. The matter of a time limit on resource development to provide incentive for rapid depletion was also discussed.

While reserve cross-dedication and unitization are alternatives available to Canterra, the Board appreciates the number and complexity of the agreements necessary to accomplish those solutions. In any case, the Board does not have jurisdiction to order such actions but encourages Canterra to further investigate them.

In Decision 80-6 and again in Inquiry Report D 83-12, the Board expressed its views regarding the appropriateness of setting a time limit on resource development in the area. At the time of issuance of Decision 80-6, the Board believed that a 12-year period would be proper for a guaranteed producing period. It had in mind a review of the situation after 12 years and recognized that a further extension could very well result if urban development had not proceeded to the point where the abandonment of the producing facilities was warranted.

Circumstances have changed since 1980 in that growth of the city has slowed dramatically and a reassessment of the potentially recoverable reserves indicates that the Board's 1980 estimates were likely on the low side. Additionally, the Board must be cognizant of the fact that the project did not proceed with the 12-year limit imposed, suggesting that it was perhaps not economically viable with the 12-year limit.

The Board calculated the payout period for the proposed pipelines and facilities to be less than the 12-year break-even period cited by Canterra. However, it recognizes that the cost of the reserves is a significant economic factor in Canterra's payout estimates and for that reason accepts the 12-year estimate. Deliverability projections suggest that little more than one-half of the recoverable reserves in place would have been produced during that period, whereas a 15-year period would mean that almost two-thirds of the reserves might be produced. These factors, coupled with the slowdown in urban development, suggest that a 15-year producing period from the date of issuance of this report would represent a reasonable balance between the need to recover the subsurface resources and the desire to see urban development proceed. The Board would review the situation at the end of the 15-year period and if appropriate, might extend the producing period. The Board is not prepared to leave the question of an extended period to the surface owners and the City as was suggested by one of the interveners but unquestionably would have regard for their views in assessing whether an extension was appropriate.

The Board recognizes that a 15-year producing period, subject to extension at the end of the period, places the surface owners and local authorities in a difficult position in terms of planning for future urban developments. For this reason, the Board believes it appropriate to provide for the possibility of the review any time after 10 years. It must be emphasized that the review would be with respect to the extension of the 15-year period but where surface owners believe that sufficient urban growth has occurred and that evidence can be presented to show that the 15-year period should not be extended, the Board would be prepared to look at the matter even though the 15-year period had not yet elapsed. This provision might allow better planning to take place.

The Board recognizes that land-use planning uncertainties can also occur if it issues approvals for the proposed pipelines and if the installation of them does not proceed. For this reason, the Board will also condition any approval it issues such that a review of the continuance of the approval would be made if the pipelines are not in operation two years from the date of issuance of this report.

In summary, with respect to limiting the time period for which approvals would be effective, and assuming the Board is satisfied with respect to other aspects of the proposed pipelines,

- the approvals would be for a 15-year period following the date of issuance of this report,
- the 15-year period could be extended if evidence showed such to be in the public interest,
- the review of the appropriateness of extending the 15-year period could take place, on request of an involved party, anytime after 10 years from the date of issuance of this report,
- the approval would be reviewed with the possibility of rescinding if the project has not proceeded within two years of the date of this report.

4 THE ROUTE AND SOUR GAS LEVEL OF THE PIPELINES

4.1 Introduction

Canterra submitted a preferred route and an alternative route, as shown on Figure 1. The alternative route had two possible Bow River crossing sites labelled 2a and 2b on Figure 2.

Canterra indicated that the 2b route was not an acceptable one and so concentrated its comments on the preferred route 1 and the viable alternative 2a. The Shields, in their intervention, suggested five alternative routes which are numbered S1 through S5, but later withdrew S4. These alternatives were briefly assessed and commented on by Canterra during the course of the hearing. All of these routes are identical from the 10-20 well site to point A on Figures 1 and 2. A routing north to the Petrogas Balzac plant was also discussed briefly.

4.2 Canterra's Views

Canterra listed a number of criteria used in choosing the preferred route, including:

- Maximum separation between pipeline and residences.
- Dilution of the high H_2S Wabamun gas (374.9 moles per kilomole (mol/kmol)) with Rundle gas (7.1 mol/kmol) at the first possible location, the 11-24 well-site.
- Parallelling in the right of way of an existing electrical powerline for part of the route.
- A crossing of the Bow River that was satisfactory from a geotechnical and river engineering point of view.
- Parallelling of section lines and undeveloped road allowances where possible.

These criteria reflect the views of landowners respecting the previous proposal by Amerada and addressed in Decision 80-6.

Canterra stated that the preferred route ensures a Level 1 designation, according to ID 81-3, for the portion of the pipeline south of the river, whereas the alternative route has a Level 2 designation south of the river and passes close to an unrestricted country development in SE 1/4 12-22-29 W4M.

Canterra considered the site of the preferred river crossing to have advantages over the alternative 2a site when comparing bank stability and steepness, access, and ease of construction. Some erosion protection would be needed on the north bank at the alternative site. However, Canterra agreed that both crossings were feasible and acceptable to it.

Canterra assessed river crossing sites for the alternatives proposed by the Shields and classified the S1, S2, and S3 crossings as poor from geotechnical and river engineering viewpoints.

The alternative S5 river crossing is a minor amendment to the applicant's alternative 2a and Canterra classified it as good from geotechnical and river engineering points of view and said that it would be acceptable. However, Canterra stated that the southern portion of route S5, which proceeds directly to the 11-1-22-29 W4M well then westerly to 10-2, is not acceptable because it would tend to further divide a quarter section bounded on both sides by powerlines.

Canterra calculated that an extra five ESD valves would be required to reduce the portion of the alternative route south of the river to a Level 1 facility. For that portion between 11-24 and 10-13 Canterra agreed that, if a need were demonstrated, an extra ESD valve would be installed to reduce the line to a Level 1 designation. However, calculations of risk for a Level 2 pipeline showed that the risk to an individual is approximately one in ten million, a risk Canterra considered to be negligible. Having a proliferation of above-ground valve facilities would increase the risk of damage and tend to weigh against any decrease in risk due to a reduction in the volume of sour gas emitted.

4.3 Interveners' Views

Mr. Ollerenshaw pointed out that in Decision 80-6 the Board stipulated the segment of pipeline between 11-24 and 10-13 to be a Level 1 facility and asked Canterra to agree to the installation of an extra ESD valve to achieve a Level 1 designation for that segment.

The Soutzos stated their preference for route S5 because they had observed changes to the north river bank and were concerned about its stability at the river crossing site on Canterra's preferred route. They pointed out that the island in the river valley is a natural habitat for wildlife, and were of the opinion that access to the preferred route river crossing was impractical as it involved a drive of about 4 km through a number of gates on private property.

The Lammles stated their opposition to the site of the preferred route 1 river crossing for environmental and safety reasons. Mr. Lammle explained that his family use the park-like area for recreation and that school groups are given guided nature walks. He expressed concern that the prime developable land at the top of the bank would be adversely affected. Mr. Lammle also identified proposed building sites in proximity to the preferred pipeline route (see Figure 2).

With respect to safety, Mr. Lammle pointed out that although Canterra claimed that the pipeline had a Level 1 designation south of the river on route 1, in fact the line in the river valley was a Level 2. In examining the river crossing itself, Mr. Lammle suggested that there were four or five possible river crossings in the valley. He expressed his preference for the alternative route 2a as amended by the Shields' alternative S5 in the river valley, and would favour a Level 1 pipeline, justifying the extra cost of ESD valves by the resulting increase in safety.

Mr. Uragi supported the applicant's preferred route and opposed the alternate route 2a, and the Shields' route S5.

Mr. Shields expressed his first preference for Canterra's preferred route, stating that this route has the least effect on recreational or residential development south of the river because the pipe has a Level 1 designation. In the event that the preferred route was not acceptable, Mr. Shields listed the routes in order of preference as S5, S1, S3, S2, and Canterra 2a. He requested Canterra, in considering the S5 routing, to keep the pipeline as close to the eastern boundary of the quarter section as possible. Mr. Shields also requested that the pipeline be made to conform to a Level 1 designation considering the terrain and the proximity of the subdivision to the east, but stated that he would not oppose a Level 2 facility if the Board found that the safety factors involved were such that the Level 2 facility was acceptable.

The City did not take a position with respect to the choice of route.

4.4 Board's Views

The Board is satisfied that the gas in question should go south to the Okotoks plant rather than north to the Balzac plant because of the much greater length of sour gas pipeline required on the northward route and the fact that the pipeline would parallel the city boundary for much of its length. It also rules out route S4 because it would have a closer proximity to the city and indeed, Mr. Shields withdrew the route.

The route north of the Bow River from the 10-20 well site westerly to the 11-24 well site and then south to the southern border of section 13-22-29 W4M parallels quarter section lines and utilizes the existing electrical powerline alignment. The Board accepts this portion of the route.

The Board considers the location of the crossing of the Bow River to be a critical component in the choice of route. The evidence presented by Canterra and the interveners with respect to the geotechnical and river engineering factors, and its own assessment, leads the Board to the conclusion that there is no compelling reason to choose one over the others. The Board notes that Canterra prefers the section 11 crossing but is willing to accept one in section 12.

The Board appreciates the efforts of the Shields in presenting alternative routes. In assessing those routes, the Board agrees with the conclusions reached by Canterra that a north bank crossing at B to I on Figure 2 would be preferable to one at C to J or D to S to F. Since neither of these latter crossings involve routes which have major advantages over the others or were particularly supported by participants in the hearing, the Board is dismissing them as the appropriate route. This means alternatives 2b, S2, and S3 will not be considered further. Alternative S1 when it extends south from point I to O on Figure 2 passes unnecessarily close to the significant number of residences in sections 12 and 1-22-29 W4M. For this reason it is being ruled out as the proper route.

In terms of the route south of the river crossing in section 12, the Board believes a route straight south of K to the 11-1 well would have a disadvantage of negatively impacting on the development capabilities of section 1 which has already been divided by electric transmission lines. This would rule out route S5 south of point K and reduces the consideration to a choice between the preferred route 1 with the river crossing in section 11, and the alternative 2a with a possible variation which would go from I to K somewhat east of the routing I-J-K suggested by Canterra.

The Board notes that most of the interveners, including the Shields and Lammles, preferred that the line go from I to K on a route as far east as possible. Additionally, Canterra stated a willingness to make minor changes to its route 2a in section 12 to maintain at least 100 metres (m) between the pipeline and the Shields' eastern proposed building site as shown on Figure 2. The eastern route I-K has little significant impact on Mr. Uragi's land as compared to the route I-J-K.

For these reasons, the Board believes the best alignment through section 12 would be A-B-I-K-L-M-N-G-H, with the segment I-K not encroaching more closely than about 250 m from the north-south quarter section line through the centre of section 1. The Board belives that such a route would not have a significant incremental effect on the residents in the eastern half of section 12.

In comparing the modified route 2a to the applicant's preferred route 1, the Board notes that the preferred route in proceeding westward from the southern edge of section 13, approaches within about 1.5 km of existing city boundary before turning south to cross the river in section 11. Although the timing of the expansion of the city is in doubt, the Board considers this part of the preferred route to have a disadvantage when compared to the modified 2a route farther from the city

Since the two routes (preferred 1 and modified 2a) are essentially equal in other respects, Canterra indicated a willingness to proceed on 2a as modified, many of the interveners expressed a preference for the 2a modified route, and only minimal and acceptable impacts would result on the Shields and Uragi lands where they are directly crossed by the modified 2a route, the Board believes that is the better alignment. The route the Board is prepared to approve is A-B-I-K-L-M-N-G-H as shown on Figure 2.

Respecting the question of the proper level for the line, the Board has calculated that ESD valves spaced at intervals of approximately 550 m would be required to achieve a Level 1 designation. Therefore, on the modified route 2a a minimum of twelve ESD valves would be necessary to achieve a Level 1 designation for the complete line between the 11-24 well and the A10-2-22-29 W4M well. The Board views the installation of above-ground valves at such intervals as an increase in the risk of damage to the pipeline of such magnitude as to negate the advantages gained in the reduction of release volumes. Therefore, the Board will not require the entire pipeline to conform to Level 1 requirements.

For the section of pipeline between the 11-24 and 10-13 wells, two extra ESD valves would be necessary to achieve a Level 1 designation. The Board sees no immediate need for these ESD valves because the urban encroachment anticipated in Decision 80-6 has not yet occurred and the City has restricted annexation of those lands. Future country residential development could accommodate the 100-m setback if necessary. However, the Board may require installation of extra ESD valves when it perceives a need.

To achieve a Level 1 designation in the river valley on the modified 2a route would require the installation of an ESD valve on the river flood plain on the south side of the river. The Board considers that this would be poor engineering practice due to the risk of flooding, ice scour, and poor access during the winter, and will not require such a valve.

The Board calculates the potential H_2S release volume between the valves which would be installed at the top of the river bank on each side of the river, would be approximately 600 m^3. This is at the low end of the range of Level 2 release volumes and in the Board's view would be acceptable from a safety viewpoint.

On the modified route 2a south of the river, five ESD valves would be necessary to achieve a Level 1 designation throughout the line. The sour gas release volume from the top of the south river bank to the A10-2 well would be approximately 1500 m^3 which is at the high end of the range of release volumes for a Level 2 facility. The Board will not require the addition of five ESD valves, but, in view of the concerns expressed by the interveners and the proximity of the residential development in section 12, the Board considers it would be prudent to reduce the release volume by adding one extra block valve. The Board will therefore require that an ESD valve be installed at an accessible point reasonably close to the midpoint of this section of the line. This would reduce release rates from each section of the line to about 750 m^3 which is at the low end of the range for a Level 2 facility. The Board considers that any risk to the residents of the development in section 12 and to the Shields would then be minimal and acceptable.

In argument, Mr. Shields requested that if the Board determined route S5 or 2a to be the most acceptable route, Canterra be asked to consult with him when the line is surveyed about the specific routing up the river bank east of his residence.

The Board agrees that Mr. Shield's knowledge of the river bank may result in a better site specific location than otherwise and accordingly encourages Canterra to involve Mr. Shields in the selection of the pipeline alignment on the south river bank east of his residence.

5 NEED FOR SPECIAL PERMIT CONDITIONS

This section of the report discusses other aspects of the proposed Canterra applications that may require special permit conditions. They include:

- construction commencement date
- testing and producing the 11-24 well
- tie-in of future wells
- preferential production of Wabamun reserves
- safety equipment and operating procedures
- emergency response planning

5.1 Construction Commencement Date

5.1.1 Canterra's Views

While Canterra initially stated that it intended to have the reserves connected to its Okotoks plant as soon as possible providing no "unreasonable conditions" were placed on the approval, it stated later that it would accept a condition to begin construction within a year of the approval of its proposed pipelines. It noted the existence of Bow River pipeline crossing construction windows of 15 March to 15 April, and 1 July to 1 September.

5.1.2 Interveners' Views

Mr. Ollerenshaw argued that the wells should be placed on production as soon as possible and that a construction commencement condition would complement any resource development time limit condition the Board might consider. He requested that any pipeline construction permits be conditioned to require the commencement of construction within one year of issuance. He also stated that if construction was not started within the required time, the project should be eliminated, the wells abandoned, and the recovery of the reserves foregone.

5.1.3 Board's Views

The Board is prepared to include a condition regarding the start of pipeline construction within one year. As indicated in section 3.3 it is also prepared to initiate proceedings to review the continuance of the approvals if the line was not in operation within two years of issuance of this report.

5.2 Testing and Producing the 11-24 Well

5.2.1 Canterra's Views

Canterra stated that the deliverability of the 11-24 well was not needed in the first years of production to meet its contract rate and noted that the 11-24 well was not a particularly productive well in comparison to 10-13. Accordingly, it proposed to use the 11-24 well to monitor the decline in reservoir pressure with production from the 10-13 well until the 10-13 well could no longer meet the contract rate, at which time 11-24 would be tied in and produced.

Canterra agreed that production testing of the 11-24 well would provide a better estimate of not only the well's production capability but also the extent of the Wabamun reserves in the vicinity of the city. Canterra advised that extended production testing of the 11-24 well could be done relatively easily by temporarily connecting the well to the proposed pipeline and would not require the flaring of any sour gas. It undertook to conduct such a test as soon as possible after completion of pipeline construction and stated that land-use related issues should not be decided until information from a production test of 11-24 is complete.

5.2.2 Interveners' Views

Mr. Ollerenshaw argued that the 11-24 well should be adequately tested prior to any pipeline construction and, if it was not producible, then the well should be abandoned and the proposed pipelines relocated to the east, farther away from the city. In that case there would be no impacts to Mr. Ollerenshaw's land from development setbacks from sour gas facilities.

The Pearsons requested that Canterra be required to immediately commence production from the 11-24 well.

5.2.3 Board's Views

The Board agrees that testing the 11-24 well will indicate the production capability of the well and provide needed information about the extent of the Wabamun reserves, particularly underlying lands adjacent to the current city boundary and to the north of the 11-24 well. The Board notes Mr. Ollerenshaw's position that the well should be tested prior to any pipeline construction, however, it believes that production testing of the 11-24 well into the pipeline would obtain the desired information without extended periods of sour gas flaring. Accordingly, the Board will not require Canterra to test the well prior to any pipeline construction.

The Board considers the test information to be obtained to be important in view of the potential impacts resource recovery may have on future land-use planning of the area and therefore will require that the testing of the 11-24 well begin within one month of commissioning of the pipeline. The test data would be filed with the Board upon the completion of testing and would be available to interested parties.

Regarding the suggestion that the Board require the tie-in of the 11-24 well for the purposes of continous production, the Board believes the results from the 11-24 well test will determine the relative production capability of the 11-24 well to the 10-13 well and allow Canterra to further evaluate the timing of connecting the well. Regardless, the Board accepts that production from the 11-24 well should not be needed to fulfill Canterra's contractual obligations and is of the view that the producing both the 11-24 and 10-13 wells or producing the 10-13 well alone for that period of time when Canterra is constrained by gas markets will not materially affect the overall reserve recovery. Nevertheless, the Board encourages Canterra to connect the 11-24 well as soon as possible to incrementally increase the recovery of reserves underlying section 24, but for the above reasons will not require the tie-in at this time.

5.3 Tie-in of Future Wells

5.3.1 Canterra's Views

While Canterra stated that it had no plans to tie in any other wells to its proposed pipelines at this time, it noted that there was a potential drilling site in section 19-22-28 W4M.

5.3.2 Interveners' Views

Both Mr. Ollerenshaw and the Pearsons requested that the Board condition any permits to not allow the tie-in of other wells. Several other interveners supported this.

5.3.3 Board's Views

The Board recognizes that many factors including markets and available plant processing capacity affect an operator's decision to drill new wells. While Canterra has stated that current markets are poor, processing capacity limited, and that it has no immediate drilling plans, the Board is hesitant about hindering possible depletion acceleration should conditions change. Therefore, it will not condition Canterra's applications to preclude the tie-in of new wells, but rather, will review any future applications on their relative merits at the time they are made.

5.4 Preferential Production of Wabamun Reserves

5.4.1 Canterra's Views

Canterra proposed to produce from both the 10-20 and 10-13 wells and blend the resulting production from the Wabamun and Rundle pools. It stated that a blend of the gas from the two pools is required to meet the gas sales contract, bearing in mind the limitations of its gas processing capacity.

Canterra observed that if it were to produce Wabamun gas alone it would not be able to meet its sales contract on high demand days. Imposition of a condition to maximize the higher H_2S content Wabamun production would limit its operating flexibility because eventually the Wabamun wells would not be able to supply the contracted rates.

In any event, Canterra undertook to maximize Wabamun production subject to its gas contract and plant processing constraints, noting that processing of the more sour Wabamun gas resulted in an incrementally larger by-product (sulphur) revenue stream.

5.4.2 Interveners' Views

Mr. Ollerenshaw questioned Canterra about producing the more sour Wabamun gas in preference to the Rundle gas so that the Wabamun reserves underlying his property could be depleted within the 30-year timeframe of the City's annexation study. He argued that those reserves, being in close proximity to the city and underlying lands with high potential for urban development, should be produced in preference to the Rundle gas.

The Pearsons argued that the Rundle reserves should be depleted at the same time because they were concerned that the pipeline would form an artificial barrier to continuing urban development, which could result in decreased land values.

5.4.3 Board's Views

The Board agrees with Mr. Ollerenshaw that emphasis should be placed on the production of Wabamun reserves because of their proximity to the city and the urban potential of the area. Although it recognizes the Pearsons' concern, it does not believe that a pipeline carrying only the lower H_2S content Rundle gas would seriously impact urban expansion.

The Board expects that, from a business point of view, Canterra would maximize Wabamun gas production to the extent possible and is satisfied with its undertaking in this regard. Accordingly, it will not condition any permits issued to require Canterra to preferentially produce the Wabamun reserves.

5.5 Safety Equipment and Operating Procedures

5.5.1 Canterra's Views

Canterra stated that the proposed facilities north of the Bow River would be visited and checked daily by its Okotoks field personnel who also operate its existing facilities south of the river. It indicated that the existing supervisory system would be extended to allow its Okotoks plant staff to continuously monitor the operation of the proposed pipeline. Canterra proposed to install two H_2S sensing detectors, complete with alarms at the plant control room, at the well sites, one to be located on the wellhead and the other to be located in the heater building. It stated that if an H_2S concentration exceeding 10 parts per million was detected, the alarm would go off.

Canterra also proposed fail-close, high/low-pressure sensing ESD valves at the well sites and selected locations along the pipeline in addition to subsurface safety valves on its producing wells. While it noted that special construction methods would be used for ESD valve sites in close proximity to high voltage transmission lines, it stated that the operation of those ESD valves would not be affected by the transmission line.

Canterra noted that the ESD valves could also be remotely actuated using the supervisory system and would be tested monthly by simulating a low pressure in the pipeline and by remotely actuating the valve.

When questioned about its proposed method of leak detection Canterra said it would conduct an annual leak detection survey along the pipeline route. It claimed that the equipment necessary to install a mass measurement material balance leak detection system, costing approximately $30 000-35 000 per well site and $55 000-60 000 for the necessary main computer, was too expensive and observed that if a pipeline rupture were to occur, the ESD valves would close automatically.

Canterra stated that the river crossing location would be inspected monthly to monitor the effectiveness of proposed erosion control measures until the areas affected by construction are revegetated, after which the crossing would be inspected annually in conjunction with the leak detection survey.

Canterra said it planned to continuously inject three types of corrosion inhibitors (soluble in the condensate and water produced and dispersable in the gas produced, respectively) at the well sites to prevent internal corrosion of the pipeline. It would monitor for internal corrosion and determine the effectiveness of its inhibition program by using weight-loss coupons at selected locations, X-ray, and ultrasonic techniques to monitor for changes in pipe wall thickness, and produced fluid analysis at the plant (for inhibitor carry-over). It stated that while pigging facilities would not initially be required during routine operations, the piping design allowed for the addition of those facilities should they become necessary. It advised that the pipeline would accept internal electromagnetic inspection tools, capable of monitoring for internal corrosion.

Respecting external corrosion, Canterra said that both the urethane foam insulated sour gas pipeline and the fuel gas pipeline would be wrapped with a polyethylene coating, electrically isolated from well site piping and cathodically protected.

5.5.2 Interveners' Views

In his intervention, Mr. Ollerenshaw listed safety related equipment and procedures he believed should be used on the proposed pipeline. The equipment recommended included: subsurface safety and fail- close, high/low-pressure sensing ESD valves with "operator override capability", line heater emergency shut-downs, a leak detection system, check valves at junctions, and a supervisory system so that the operator at the Okotoks gas plant could monitor the status of valves and detect any emergency situations.

The procedures he requested be pipeline construction permit conditions were: semi-annual leak detection surveys, semi-annual testing of all ESD devices, and internal and external corrosion control programs.

The Pearsons stated that Canterra's proposed ". . . daily checks on wellsite facilities, monthly tests of ESD block valves, and annual surveys for minor leaks along the length of the line . . ." should be considered minimum requirements and said that semi-annual leak detection surveys should be instituted for the section of pipeline parallel to the TransAlta Utilities Corporation (TransAlta) powerline as well as the river crossing segment. They requested that an ESD valve be located at the 11-24 well site and that all of the pipeline design and safety considerations previously proposed by Amerada (as detailed in Decision 80-6) be implemented.

The Shields questioned Canterra about its proposed programs for corrosion control and the remote operation of ESD valves in proximity to the TransAlta powerline. They also wanted assurances that all pipeline welds would be 100 per cent X-rayed by an independent inspection company and tested prior to service, that the pipeline coating be inspected for holidays by an independent inspection company, and the welding personnel used be qualified to meet the required standards.

5.5.3 Board's Views

The Board notes that Canterra proposes to utilize essentially all of the equipment mentioned by Mr. Ollerenshaw, with the exception of a mass measurement material balance leak detection system. It accepts Canterra's cost estimates for the equipment and concurs that a sophisticated leak detection system is not needed at this time. However, the Board maintains its view as set out in Decision 80-6 that such equipment may be required in the future.

With respect to the operating conditions requested by Mr. Ollerenshaw the Board recognizes that the frequency of leak detection surveys are established by individual operators having regard for, among other things, the condition of the pipeline and density of population of the area. It notes that the frequency of leak detection surveys proposed by Canterra (annual) is less than the frequency previously proposed by Amerada and requested by Mr. Ollerenshaw (semi-annual). The Board is aware that Canterra currently conducts annual surveys of its operations south of the river and believes that because the pipeline would be new an annual survey should be sufficient to detect minor leaks if they occur. Further, the Board sees no reason to require semi-annual surveys for the pipeline river crossing or the pipeline parallel to the TransAlta powerline.

The Board has reviewed the requirements of the Canadian Standards Association standard Z184-M1983[2] Gas Pipeline Systems respecting ESD valve operation and believes Canterra's proposed inspection and test procedures are satisfactory. Further, the Board is of the view that ESD valves in proximity to high voltage transmission lines can be reliably operated.

The Board believes that Canterra's proposed corrosion control program is appropriate, having regard for the purpose and location of the proposed pipeline and that the program meets the requirements of CSA Z184-M1983 and the Pipeline Regulations.

The requirements for welder qualifications and weld and pipeline coating inspections are detailed in CSA Z184-M1983. Part 7 of the Pipeline Regulations sets out the requirements for pipeline testing. These requirements will be satisfied in accordance with the application.

The Board believes a subsurface safety valve as well as an ESD wellhead valve at the 11-24 well would be required when the well is connected to the pipeline.

In summary, the Board is satisfied with the safety related equipment and operating procedures proposed by Canterra and, accordingly, will not condition the pipeline construction permits in this respect.

5.6 Emergency Response Planning

5.6.1 Canterra's Views

Canterra stated that its existing emergency response plan for the Okotoks Field would be expanded to include residents potentially affected by its proposed facilities north of the Bow River. It said that the plan contains an information and education program to advise residents about its normal operations and possible response procedures should an emergency occur. The plan is updated on a regular basis. It contains the names, locations, and telephone numbers of area residents as well as others who might become involved such as the RCMP. It also contains details respecting available emergency rescue equipment and response procedures for various types of potential emergency situations.

Canterra stated that a procedure has been established whereby, in an emergency such as a well blowout or pipeline rupture, residents are contacted by telephone and advised of either the most prudent evacuation route or to remain indoors to minimize H_2S exposure times, depending on the nature of the emergency. It emphasized that its operations are monitored on a 24-hour basis by the Okotoks plant operating staff and advised that on-call staff were available to implement its plan. Canterra mentioned that in special instances, such as the drilling of a new well or a well test or workover, it has in the past implemented a supplementary type of emergency response plan. For example, when drilling a new well the supplementary plan provided for a 24-hour patrol and surveillance of the area as well as a rehearsal of its evacuation plan prior to drilling into the geologic formation potentially containing sour gas.

In response to the Pearsons' concern about evacuation of cattle, Canterra stated its first priorities in an emergency were the human residents but added that it believed that its proposed facilities would be sufficiently distant to minimize the effects on cattle of any potential H_2S release.

In response to questions about the possible evacuation of acreage residents in the SE 1/4 20-22-28 W4M, including the Workman Group, Canterra said that in the event of a worst case emergency, such as a well blowout, and where only one evacuation route is available, rescue might involve the repeated use of self-contained breathing apparatus to remove the people affected. However, it was of the view that in the case of a pipeline rupture, residents would best be advised to remain indoors having regard for the short duration of such an H_2S release.

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[2] Canadian Standards Association, 1983. *Gas Pipeline Systems, Pipeline Systems and Materials*. Standard Z184-M1983. Rexdale, Ontario.

5.6.2 Interveners' Views

The Lammles noted their residence is located within the river valley, and access is limited to one route. They expressed concern about their safety in the event of a pipeline rupture.

The Shields said access to their river valley residence is difficult in winter and they were concerned about possible evacuation. The Shields stated "... that the procedure outlined by Canterra of phoning people could be improved upon" and recommended that the plan include provision to visit individuals should there be no answer on the phone. The Shields believed there should be an extensive emergency plan for informing and evacuating people and requested the Board require Canterra to rehearse its evacuation plan at suitable intervals.

The Pearsons questioned Canterra about its evacuation procedures for not only residents but also for their cattle and pointed out that there was only one access to their residence. They contended that residents in the area should be advised of any new plans for emergency response procedures as a result of the proposed pipelines.

The Workman Group was concerned that evacuation of the numerous residents located in the country residential development in the SE 1/4 20-22-28 W4M would be difficult because access to the area is by a dead-end road.

5.6.3 Board's Views

Interim Directive No. ID-OG 76-2[3] requires operators of sour gas processing plants, wells, and pipelines to develop emergency response plans to ensure the safety of residents that might be affected in the event of a release of sour gas. The plans describe the subject facilities including potential H_2S release rates (wells) and volumes (pipelines), evaluate potential emergency situations that may arise, and set out procedures to be followed. The procedures address the locating of hazardous areas in the event of a release, define the steps to notify and if necessary evacuate residents potentially affected, and detail the necessary communications and contacts to implement the plan. Responsibilities of various company personnel and available emergency equipment are also set out in the plan as well as provisions for its updating.

The Board notes that Canterra's existing sour gas emergency response plan for its facilities in the Okotoks Field has been in operation for some time and that the plan is periodically reviewed and updated.

The Board agrees with the Shields that the plan should include provisions for follow-up visits should Canterra not be able to contact a resident by telephone and that rehearsals may provide useful insight into the actual implementation of the plan. In the past, the Board has required the filing of emergency plans, including those cited by Canterra, for specific operations such as drilling new wells or workovers that might result in short-term increased hazard. The Board will continue to review the need for such plans on a specific situation basis.

In that the Board's requirements provide that operators train their personnel regarding the implementation of their respective plans, and because the Board believes that the hazard associated with the normal operation of the proposed pipeline and wells would be less than during drilling or workovers, rehearsal of the overall plan will not be required at this time.

The Board is concerned about area residents that have only one egress route in the event of an emergency. While it notes Canterra's statements regarding the need for and mechanics of evacuation in such situations, it believes that Canterra's plan must make special provision for residents having only one access route.

The Board notes that Canterra meets with individual residents in the process of developing and updating its plan and, as suggested by the Pearsons, encourages Canterra to maintain periodic communication with residents to advise them of any significant revisions to its plan. Further, because the proposed pipeline could impact residents not currently affected by the existing pipelines in the area, the Board will grant approval for the facilities only if the plan is satisfactory to it. Additionally, the Board will require Canterra to inform residents of the area of its plan, not more than 4 weeks prior to commissioning the pipeline, and provide them with an opportunity to discuss the plan further.

6 PIPELINE DESIGN

This section of the report discusses general pipeline design features not addressed in section 5.

6.1 Canterra's Views

Canterra's pipeline design is based on the CSA Z184-M1983 Gas Pipeline Systems design code.

For the sour gas pipeline, Canterra plans to use new CSA Z245.3[4] Grade 290 Category II pipe and ASTM A333[5] Grade 6 seamless pipe with a maximum operating pressure of 7240 kilopascals (kPa). It stated that the pipe would also conform to Canterra's stringent supplementary specification for sour gas service and that the necessary valves and fittings would meet NACE Standard MR 01-80[6].

---

[3] Energy Resources Conservation Board, 1976. *Emergency Procedure Plans for Sour Gas Facilities*. Interim Directive ID-OG 76-2. Calgary, Alberta.

[4] Canadian Standards Association, 1979. (Now Z245.1-M1982) *Steel Line Pipe, Pipeline Systems and Materials*, Standard Z245.1-M1982. Rexdale, Ontario.

[5] American Society for Testing and Materials, 1982. *Seamless and Welded Steel Pipe for Low-Temperature Service*. ASTM standard A333-82. Philadelphia, Pennsylvania, USA.

For the fuel gas pipeline, Canterra proposes new CSA Z245.3 Grade 290 Category I pipe and ASTM A333 Grade 6 seamless pipe with a maximum operating pressure of 5860 kPa.

6.2 Board's Views

The Board is satisfied that the pipeline design proposed by Canterra meets the requirements of CSA Z184-M1983 and the Pipeline Act and Regulations, and is acceptable for the intended service.

7 SOUR GAS CONSTRAINT

7.1 Interveners' Views

7.1.1 City of Calgary

Mr. E. C. Brown confirmed that the City had placed a sour gas constraint on various lands after discussions with the ERCB. As a result, the lands were excluded from the City's February 1983 annexation study. Mr. Brown explained that while City council had reviewed the February 1983 annexation study, it believed a more fundamental review of various growth strategies should be done, and accordingly had undertaken such a review. Mr. Brown stated that when the review is complete (probably in 1985) the City will again begin to consider annexation alternatives.

Mr. Brown was uncertain when the lands adjacent to the eastern boundary of the city would be needed for urban development. He said that depending on the growth rate of the city, the lands could be developed in 10-20 years. Lands immediately adjacent to the city boundary, in particular section 23, probably would have been considered for annexation if there was no sour gas constraint.

Mr. Brown stated that while the developable lands within the current boundaries potentially represent a 20-year supply, lands outside the city might be developed first because of better servicing and/or accessibility considerations.

7.1.2 Mr. Ollerenshaw

Mr. G. Brown, who appeared as a planning consultant on behalf of Mr. Ollerenshaw, reviewed the development potential of Mr. Ollerenshaw's property and said the lands had no natural or topographic constraints to urban development. They are readily accessible by existing transportation facilities and could easily be serviced. Mr. Brown pointed out that the Ollerenshaw lands were adjacent to the current boundary of the City and indicated that the W 1/2 23-22-29 W4M had been included in a concept plan prepared in support of an annexation proposal for other lands recently annexed by the City.

Mr. Brown said that a February 1983 City of Calgary annexation study excluded lands to the east of Calgary, including Mr. Ollerenshaw's, because of a "sour gas constraint" on the area. The City had placed this administrative constraint on the subject lands after discussing the potential for sour gas development of the area with the ERCB. He suggested that lands not affected by the minimum setback requirements of ID 81-3 were suitable for urban development and said that if the Board were to refine and clarify the sour gas constraints from the existing wells and proposed pipelines, and advise the City, then the Ollerenshaw lands could be included in future annexation proposals. Mr. Brown estimated that development of the general area would take approximately 10-20 years with resulting population of 80 000 to 100 000 people.

7.2 Canterra's Views

While it did not present evidence regarding the potential for urban development of lands within the sour gas constraint area, Canterra questioned Mr. Ollerenshaw and the City about the need for lands for expansion considering the current supply of developable lands within the City. Canterra expressed a view that there would not be any conflict between urban development and resource recovery for about 20 years.

7.3 Board's Views

The Board believes that the "sour gas constraint" used by the City is a useful development planning tool in that it identifies potential land- use conflicts. The Board recognizes that the placing of such a constraint on lands could have a significant impact on the owners. In such instances and where the owner disagrees with the designation of a sour gas constraint, the Board would generally be prepared to meet with the landowners, the resource operators, the City, and other potentially affected parties, to review the need for and details of the constraint.

The Board is not prepared at this time to make such a review with respect to Mr. Ollerenshaw's lands in section 23 and 24-22-29 W4M, because the hearing was not called for that purpose, but rather to consider the pipeline applications being dealt with in this report. When the results of the production test of the 11-24 well (referred to in section 5.2) are available the Board would consider a review if requested to do so.

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[6] National Association of Corrosion Engineers, 1980. *Material Requirement, Sulfied Stress Cracking Resistant Metallic Material for Oil Field Equipment*. NACE Standard MR-01-75 (1980 Revision). Houston, Texas, USA.

8 DECISION

The Board is prepared to issue the appropriate pipeline construction permits to Canterra Energy Ltd. for the applied-for lines in the route shown on Figure 1 from the 10-20-22-28 W4M well to point A, and on Figure 2 for the segment A-B-I-K-L-M-N-G-H. The permits would be subject to the installation of an additional ESD valve on the pipeline as discussed in section 4.4 of this report.

The pipeline permits will also have the following conditions attached:

(1) Construction authorized by this permit shall commence prior to 11 May 1985.

(2) The permittee shall connect the 11-24-22-29 W4M well to the pipeline authorized by this permit within one month of commissioning of the pipeline, for the purposes of testing the 11-24 well through the pipeline to the Canterra Okotoks gas plant.

(3) The permittee shall update its emergency response plan in a manner satisfactory to the Board and, not more than four weeks prior to the commissioning of the pipeline, shall inform residents in the area of the plan.

The Board will initially limit resource recovery in that portion of the Okotoks Field north of the Bow River to 15 years and will review its approval if the pipelines are not in operation by 11 May 1986.

The pipeline permits will be issued subject to the above conditions and following:

- receipt of the approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act, and
- receipt of the consent of the Minister of the Environment pursuant the Calgary Restricted Development Area Regulations.

ISSUED at Calgary, Alberta, on 11 May 1984.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

V E Bohme

V. E. Bohme, P.Eng.
Board Member

APPENDIX

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canterra Energy Ltd. (Canterra) F. Saville C. Morel	L. E. Fenwick, P.Eng. J.D.C. Carmichael, P.Eng D. H. Davies D. A. McCoy N. F. Lenstra, P.Eng. of Lalen Consulting Ltd. M. Stepanek, P.Eng. of Hardy Associates (1978) Ltd. Dr. D. M. Leahey* M. B. Schroeder* * of Western Research, Division of Bow Valley Resources Sevices Ltd.
B. Lammle and M. Lammle (the Lammles)	B. Lammle
L. McKeag[1]	
A. Moeller	
F. J. Ollerenshaw S. Carscallen	R. F. Ollerenshaw G. N. Brown C. W. Van Bussel, P.Eng. I. Martin, P.Eng.
D. Pearson and R. Pearson (the Pearsons)	D. Pearson
R. Shields and V. Shields (the Shields)	R. Shields
C.G. Soutzo and A.G. Soutzo (the Soutzos) M. A. Putnam, Q.C.	C. G. Soutzo A. G. Soutzo
K. Uragi K. W. Stilwell	
D. Workman (Workman Group) L. E. Thompson L. G. Thompson D. Walker G. Paradis L. Paradis B. McKinstry B. McKinstry J. Pawluk M. Pawluk L. McKeag A. McKeag	D. Workman

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations used in Report)	Witnesses
City of Calgary (City) E.C. Brown	E.C. Brown
Committee for Toxic Pollutant Controls (CTPC) D. J. Evans	
Her Majesty the Queen in the Right of the Province of Alberta (Crown) T. Bossenberry	
Energy Resources Conservation Board staff R. Hansford D. A. Holgate A. Cassley, P.Eng. H. W. Knox, P.Eng.	

---

[1] L. McKeag was also represented by the Workman Group.

E. Shamash filed a submission but did not appear at the hearing.

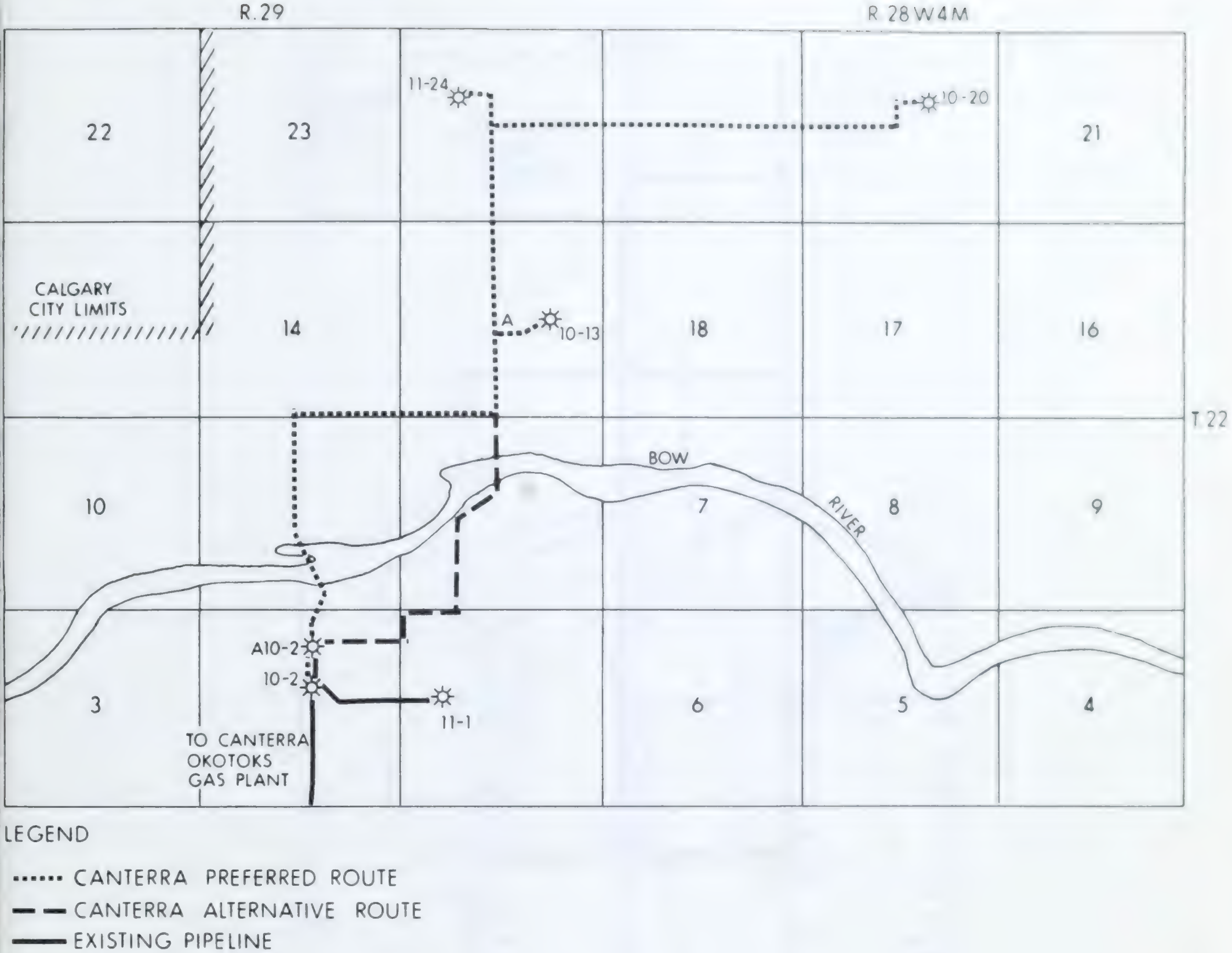
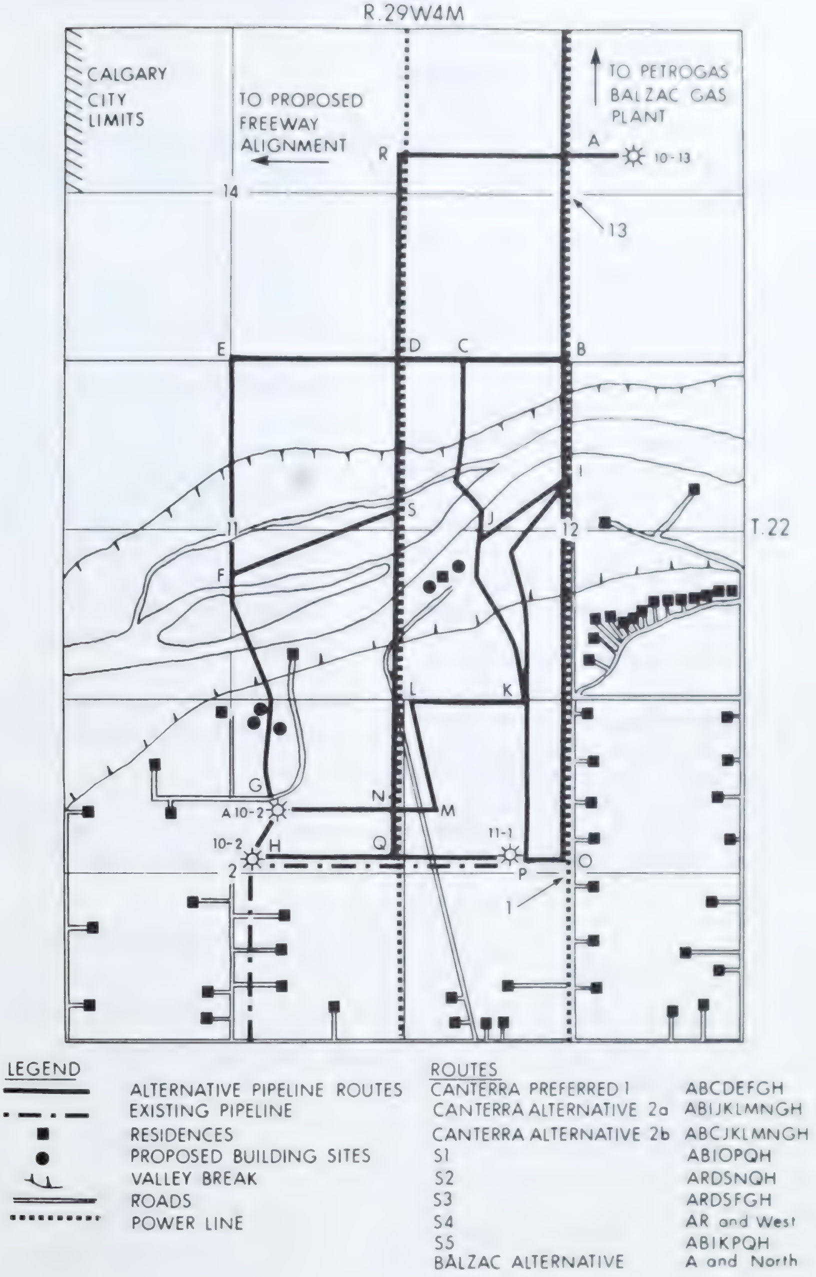


FIGURE 1

CANTERRA ENERGY LTD. PROPOSED PIPELINES
CALGARY AREA



LEGEND

▬	ALTERNATIVE PIPELINE ROUTES
— · — ·	EXISTING PIPELINE
■	RESIDENCES
●	PROPOSED BUILDING SITES
⌣	VALLEY BREAK
═	ROADS
········	POWER LINE

ROUTES	
CANTERRA PREFERRED 1	ABCDEFGH
CANTERRA ALTERNATIVE 2a	ABIJKLMNGH
CANTERRA ALTERNATIVE 2b	ABCJKLMNGH
S1	ABIOPQH
S2	ARDSNQH
S3	ARDSFGH
S4	AR and West
S5	ABIKPQH
BALZAC ALTERNATIVE	A and North

FIGURE 2
ALTERNATIVE PIPELINE ROUTES
BOW RIVER AREA

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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AMOCO CANADA PETROLEUM COMPANY LTD. APPLICATION FOR A WELL LICENCE

Decision D 84-8
Application 830789

1 THE APPLICATION AND HEARING

Amoco Canada Petroleum Company Ltd. (Amoco) applied for a well licence for a well to be located in legal subdivision 6 of section 6, township 54, range 25, west of the 4th meridian (the 6-6 well). Amoco indicated the purpose of the well would be to obtain oil production from the Wabamun (D-1) formation. It indicated that the well would penetrate the Nisku (D-2) formation and, although there was a remote possibility that it would produce oil, the main reason for penetrating the D-2 was to establish the top of the formation and gain further well control for possible additional wells in this area. The natural gas in the reservoirs are expected to have hydrogen sulphide (H_2S) concentrations of 6.5 moles per kilomole (mol/kmol) and 18.3 mol/kmol for the D-1 and D-2, respectively.

The location of the proposed well relative to the corporate limits of St. Albert and certain other landmarks is shown on the attached figure.

A public hearing of the application was held in St. Albert on 9 April 1984, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. R. Brushett, P.Eng., sitting.

The City of St. Albert (City) and Genstar Development Company (Genstar) appeared at the hearing. Neither of the interveners objected to the issuance of the applied-for well licence, provided that a number of conditions outlined in subsequent sections of this report were met.

2 THE ISSUES

The Board considers the issues with respect to the application to be:

- the need for the well,
- the safety of the public during the drilling of the well, and
- if the well is successful, the safety of the public during the producing life of the well.

3 AMOCO'S VIEWS

Amoco stated that a well was needed on the SW 1/4 of section 6, township 54, range 25, west of the 4th meridian, to evaluate and obtain production from the D-1 formation. Amoco indicated that it was entitled to produce oil from beneath the SW 1/4 of section 6 by way of an agreement with the freehold owners of those mines and minerals. The agreement committed Amoco to drilling

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco)	
A. L. McLarty	R. Findlay B. McDonald, P.Eng. L. Cyca, P.Eng. L. Field, P.Eng.
L. M. Pillman	
S. E. Lipton	
The City of St. Albert (City)	
S. T. Brown	
Dr. A. Lamb, P.Eng.	
Genstar Development Company (Genstar)	
G. L. Stebner, P.Eng.	
Energy Resources Conservation Board staff	
M. J. Bruni	
J. R. Nichol, P.Eng.	
B. M. MacKay	
G. D. Agnew	

a well prior to 29 September 1984 in order to avoid the expiry of a portion of its lease agreement. Amoco indicated that if its geological prognosis of the area is accurate and a well were not drilled, an estimated 30 000 cubic metres (m^3) of oil would remain unrecoverable. On the basis of its current geological picture, Amoco said that it might drill two additional wells west of the proposed location and farther away from St. Albert.

Amoco stated that while surface rights to the land have not been obtained, the various parties having an interest in the surface have agreed to the location of the well and the access road. The well would take some 20 days to drill.

Amoco calculated a maximum H_2S release rate of 0.05 cubic metres per second on the basis of the maximum expected flow rates from both the D-1 and D-2 zones combined. Amoco noted that under present Board directive ID 81-3[1] this would be at the lower end of the range for a Level 1 sour gas facility. This is the grouping with the lowest release volumes, and the directive prescribes a minimum separation distance of 100 metres (m) from Level 1 wells to dwellings.

As the corporate limits of St. Albert are 420 m to the east and the nearest residence from the well centre is 550 m, Amoco indicated that the requirements for a Level 1 sour gas facility were clearly satisfied. It said that notwithstanding this, because of the proximity to St. Albert and nearby residences, it would prepare a map showing the road system and residences within 1.5 kilometres (km) of the well, a list of telephone numbers of the residences, and a listing of emergency service numbers in case the unforeseen should occur and a blowout take place. This would be done just prior to spudding the well to ensure the most up-to-date accuracy and a copy would be supplied to the City and the Board.

Amoco also indicated that it would take special and extraordinary precautions in the drilling of the well. These included posting of H_2S warning signs at the location entrance, the employment of additional and experienced supervisors to ensure 24-hour coverage, the installation of combustible gas and H_2S detection equipment with alarms, a mud system specially designed for H_2S, a supply of H_2S scavenger to be stored on site, a completely equipped safety trailer, a closed vehicle located on site and suitable for emergency personnel transport, fixed and mobile radio telephone communication, and provisions with respect to igniting the well in the event of a release of sour gas which posed a danger to the public. Sour specification drilling equipment including blowout preventers (BOPs), choke manifold and drill pipe would also be used, and the mud system would be equipped with two open-ended degassers placed in parallel.

If the well is successful and is completed as an oil well, Amoco indicated that the production would be pipelined south and west to its existing tank battery in section 36. If a pump was installed, an electric motor would be used to minimize noise. A fence would be constructed, if necessary, or if required by the Board.

As a result of questions raised in the press, Amoco compared the proposed well to the Lodgepole 13-12 blowout well. It indicated that the D-1 production in the subject area is oil as opposed to gas, the H_2S content is much less, at 6.5 mol/kmol compared to 230 mol/kmol for Lodgepole. The end result is a maximum potential H_2S release rate of only 1/1000 of that of Lodgepole. Amoco said that considerably less H_2S is expected in the proposed well than is currently being produced from the Nisku (D-3) reef in the area. This reef has been on production since the early 1950s with little inconvenience to the residents of St. Albert.

4 THE INTERVENERS' VIEWS

4.1 The City of St. Albert

The City stated that it did not oppose the application provided that it could be assured that the well would not endanger or have an adverse impact beyond that absolutely necessary on St. Albert or its inhabitants.

The City expressed the view that an accurate and up-to-date map and list of residents and their phone numbers along with emergency contact numbers should be provided by Amoco prior to drilling. Additionally, every precaution should be taken to make the drilling as safe as possible. In particular, the City referenced concerns regarding the adequacy and type of drilling equipment, gas detection equipment, and downwind monitoring equipment.

The City also indicated that any producing operations should be conducted in as safe, efficient, and compatible manner as possible. In particular, it referenced a number of measures that had been recommended in ERCB Inquiry Report D 83-F[2] to ensure that oil wells with a normal separation distance of 100 m from the nearest residence would be compatible with urban development. These measures included the following:

"(a) All wells would be equipped with high and low pressure shut-down devices.

(b) Pumping wells would be equipped with electric-drive motors and a blowout prevention device to shutoff flow from the well in the event of a rod failure.

---

[1] ERCB Interim Directive ID 81-3. Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments. December 16, 1981. Calgary, Alberta.

[2] ERCB Inquiry—Resource Development/Urban Development—West Edmonton Area.

(c) Lease equipment would be limited to that absolutely essential for the operation of the well. In particular, no permanent flaring facilities installed at the well site.

(d) Wells must be properly fenced, including a locked gate. In addition to restricting unauthorized access to the site, the fence should be designed such that it will reduce the visual impact of the facility.

(e) Good housekeeping practices and regular painting are a must.

(f) A sign giving the company name and 24-hour telephone numbers to contact must be placed in a prominent place at each well location.

(g) Trucking of oil and salt water would be prohibited except in special circumstances and only with prior approval from the Board.

(h) Electrification of the well equipment must be in accordance with the neighbourhood electrical system, including underground wiring if such is being used in the area."

The City noted that some items and/or portions thereof had been addressed to its satisfaction by Amoco at the hearing.

4.2 Genstar Development Company

Genstar did not dispute the need for the well nor did it object to issuance of the well licence providing there were no negative impacts on its lands within the city limits of St. Albert. These concerns were listed by Genstar as odours or emissions from the well, flaring or processing of gases at the well site, and nuisance noise from the well equipment.

5 BOARD VIEWS

The Board notes that neither the City nor Genstar opposed the application nor disputed the need for the well. The Board agrees with Amoco that the well has prospects for recovering substantial reserves of oil not otherwise recoverable. The Board thus believes the well should be drilled provided there would be no significant negative impacts on the surrounding residents and St. Albert.

The Board agrees with Amoco that the possibility of a blowout occurring is very low and that even if one did occur, the danger to surrounding residents and St. Albert would also be low. The Board notes that Amoco has adopted a number of extra precautionary measures such as additional crew training, full H_2S specifications for all drilling equipment, and the inclusion of additional monitoring and safety equipment, on site. The Board strongly endorses this approach when drilling a well in a sensitive area, particularly in close proximity to urban centres.

Indeed, due to the proximity of the well to St. Albert, the Board believes that a number of special requirements should be adhered to. First, a site-specific emergency procedures plan should be prepared in accordance with ID-OG-76-2[3] and filed with the Board for approval prior to commencement of drilling. The Board would so condition any licence issued and would expect a copy of the plan to be provided to the City.

The Board is satisfied that the type of equipment which Amoco plans to use and its general drilling plan, the supervisors and other personnel to be used, the provision for safety equipment, and plans for operator inspections of the rig, are all adequate and properly recognize the proximity of the proposed well to St. Albert. Since the special measures related to these items are part of Amoco's application, there is no need to condition the well licence. The Board would expect Amoco to fulfill its undertakings and additionally, requests Amoco to notify the Board's Edmonton office at least 48 hours before it would penetrate the Wabamun formation so that a detailed rig inspection can be made.

The Board does not believe that there would be any significant adverse effects associated with production operations at the proposed site should a successful well be drilled. There would be no permanent production facilities on the site, other than the wellhead and a pumping unit probably in one year's time, and all production would be pipelined to a central facility approximately 2 km to the west. Under normal operations the production would be handled in a closed system and there should be no associated odours nor would there be continuous flaring at the site.

Amoco indicated that it may be necessary to test the well prior to placing it on production. The Board would not expect adverse impacts associated with possible test operations, but would require that Amoco notify it, residents within 1.5 km, and City officials prior to any test operations. Additionally, Amoco would be expected to keep the duration of any test as short as possible and to ensure the complete combustion of any gas flared at the site.

In its closing argument, the City asked that Amoco be required to adopt a series of recommendations outlined in ERCB Inquiry Report D 83-F. These are listed in this report. The Board notes that undertakings made by Amoco would essentially meet items (b), (c), (e), (f), and (g). Item (a) is not an unreasonable expectation for the subject well and the Board will require it of Amoco. A proper fence, item (d), will be required in accordance with section 8.180(1) of the Oil and Gas Conservation Regulations if the well is equipped with a pumping unit. Item (h) is intended for wells within a residential neighbourhood and would not be applicable in the subject case.

---

[3] ERCB Interim Directive No. ID-OG-76-2. Emergency Procedure Plans for Sour Gas Facilities. October 14, 1976. Calgary, Alberta.

Given the special conditions which Amoco intends to incorporate for this well and which would be required as outlined above, the Board is satisfied that the proposed well can proceed without significant impacts on nearby residents or St. Albert. The Board does consider it appropriate, due to the proximity of the well to St. Albert, to have its field staff inspect the drilling operation and any subsequent testing or producing operations to a greater than normal extent. It is making arrangements for this to be done.

6 DECISION

The subject application is approved and a well licence will be issued to Amoco subject to the following special conditions:

- The licensee shall submit to the Board's Environment Protection Department a site-specific sour gas emergency procedures plan and have it approved by the Board prior to spudding the well.
- The Board's Edmonton office shall be advised at least 48 hours in advance of: the spudding of the well, the penetration of the Wabamun formation, and the initiation of any testing operations.

DATED at Calgary, Alberta, on 13 April 1984.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

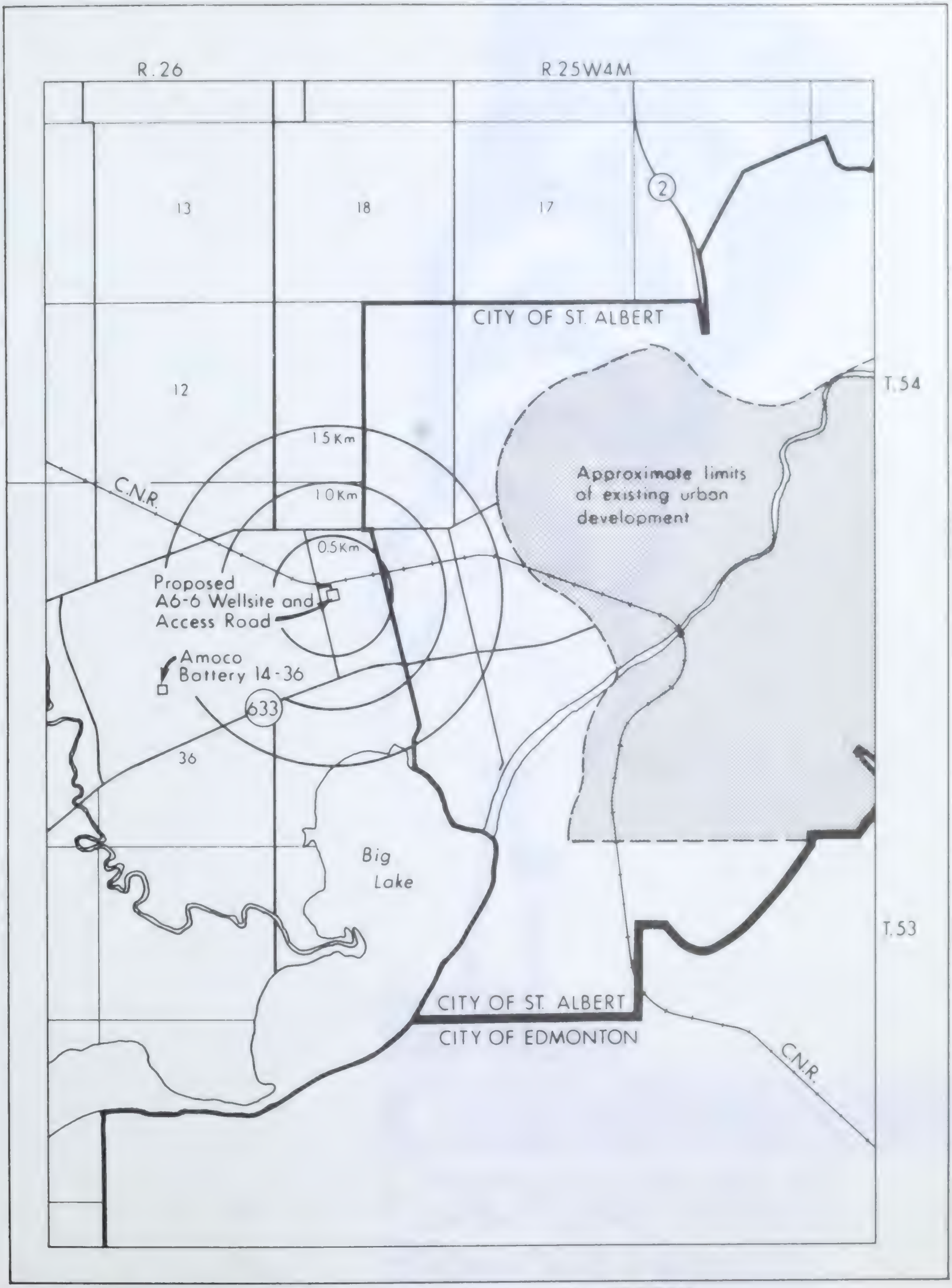
G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

E R Brushett

E. R. Brushett, P.Eng.
Acting Board Member



AMOCO'S PROPOSED WELLSITE. Application No. 830789

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LODGEPOLE BLOWOUT INQUIRY

PHASE 1 REPORT

REPORT TO THE LIEUTENANT GOVERNOR IN
COUNCIL WITH RESPECT TO AN INQUIRY HELD
INTO THE BLOWOUT OF THE WELL, AMOCO DOME
BRAZEAU RIVER 13-12-48-12

DECEMBER 1984

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LODGEPOLE BLOWOUT INQUIRY PANEL

Contents
1
2
3
4

LODGEPOLE BLOWOUT INQUIRY PANEL
DECISION REPORT

Report D 84-9 concerns

The blowout of the well, AMOCO DOME BRAZEAU RIVER 13-12-48-12, which blew out of control on 17 October 1982.

Published December 1984

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Energy Resources Conservation Board
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Calgary, Alberta
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Telex 03-821717

Price: No Charge

Contents
1
2
3
4

Contents

ERCB

CONTENTS

Page

1 SUMMARY 1-1

Introduction 1-1
What Happened at Lodgepole? 1-1
The Inquiry 1-1
Important Issues 1-1
What Went Wrong at the 13-12 Well? 1-1
Regaining Control of the 13-12 Well 1-2
Hazard to Human Health 1-3
Impact on the Environment 1-4
Responses by ERCB and Government Departments 1-4
What About the Future? 1-5
Conclusion 1-5

2 INTRODUCTION 2-1

2.1 Background 2-1
2.2 Preparations for the Inquiry 2-1
2.3 Procedural Decisions 2-1
2.4 The Inquiry 2-1
2.5 Participants at Phase 1 of the Inquiry 2-1
2.6 Phase 1 and Phase 2 Reports 2-2

3 A BRIEF REVIEW OF THE ON-SITE ACTIVITIES PRIOR TO AND DURING THE BLOWOUT 3-1

3.1 Introduction 3-1
3.2 Drilling the Well 3-1
3.3 Trouble Begins 3-1
3.4 The Blowout 3-19
3.5 Emergency Measures 3-19
3.6 Well Control Attempts Begin 3-19
3.7 Establishing Control of the Well 3-20

4 ISSUES 4-1

5 THE CAUSE OF THE BLOWOUT AND ADEQUACY OF ACTIONS TAKEN BY AMOCO TO PREVENT IT 5-1

5.1 Introduction 5-1
5.2 A General Well Control Plan 5-1
5.3 Control Factors at the 13-12 Well 5-2
5.4 Integrity of the Drilling Mud System 5-2
5.5 Integrity of the Drilling and Blowout Prevention Equipment 5-21
5.6 The Human Factor 5-26
5.7 Summary of Panel's Views 5-29
5.8 Recommendations 5-30

6 WELL-CONTROL ACTIVITIES AND THE ADEQUACY OF ACTIONS BY AMOCO AND OTHERS 6-1

6.1 Introduction 6-1
6.2 Blowout Characteristics 6-1

6.3 Appropriateness of Control Plans 6-1
6.4 Control Equipment 6-17
6.5 Safety Equipment and Procedures 6-18
6.6 The Human Factor 6-19
6.7 Summary of Panel's Views 6-19
6.8 Recommendations 6-19

7 HAZARD TO HUMAN HEALTH 7-1

7.1 Introduction 7-1
7.2 Medical Evidence 7-1
7.3 The Standards Adopted to Protect Human Health from Emissions from the Blowout 7-5
7.4 Monitoring H_2S Emissions from the Well 7-7
7.5 Adequacy of Emergency Response Plan 7-17
7.6 Evacuation of Residents Due to H_2S Concentrations 7-18
7.7 SO_2 and Other Emissions 7-21
7.8 Summary of Panel's Views 7-21
7.9 Recommendations 7-22

8 IMPACT ON THE ENVIRONMENT AND ON PERSONAL PROPERTY 8-1

8.1 Introduction 8-1
8.2 Background Information 8-1
8.3 On-Site and Immediate Area Impact 8-9
8.4 Local Regional Area 8-15
8.5 Reclamation 8-18
8.6 Summary of Panel's Views 8-18
8.7 Recommendations 8-18

9 COMMUNICATION AND CO-ORDINATION 9-1

9.1 Introduction 9-1
9.2 Communication with the Public During the Blowout 9-1
9.3 Assessment of Communication Efforts 9-3
9.4 Recommended Communication Program 9-4
9.5 Co-ordination of Responsibilities and Activities by Government Departments and Agencies 9-5
9.6 Summary of the Panel's Views 9-5
9.7 Recommendations 9-5

10 ADEQUACY OF ERCB RESPONSES FOLLOWING THE BLOWOUT, AND ITS REGULATIONS, POLICY, AND PROCEDURE 10-1

10.1 Introduction 10-1
10.2 Drilling Operations 10-1
10.3 Operations to Regain Control 10-2
10.4 Effect on the Public 10-3
10.5 Summary of Panel's Views 10-3
10.6 Recommendations 10-4

11 ADEQUACY OF THE GOVERNMENT DEPARTMENTS' RESPONSES FOLLOWING THE BLOWOUT, AND THEIR REGULATIONS, POLICY, AND PROCEDURE 11-1

11.1 Introduction 11-1
11.2 Drilling Operations 11-1
11.3 Operations to Regain Control 11-1

11.4 Effect on the Public 11-2
11.5 Summary of Panel's Views 11-3
11.6 Recommendations 11-3

12 FINDINGS AND RECOMMENDATIONS 12-1

12.1 Introduction 12-1
12.2 The Cause of the Blowout and the Adequacy of Amoco's Actions 12-1
12.3 Well-Control Activities and the Adequacy of Actions by Amoco and Others 12-3
12.4 Hazard to Human Health 12-3
12.5 Impact on the Environment 12-4
12.6 Communication and Co-ordination 12-5
12.7 Adequacy of ERCB's Responses Following the Blowout, and its Regulations, Policy, and Procedure 12-5
12.8 Adequacy of the Government Departments' Responses Following the Blowout, and Their Regulation, Policy, and Procedure 12-6
12.9 Summary 12-6

13 SIGNIFICANCE OF INQUIRY RECOMMENDATIONS IN REDUCING THE POTENTIAL FOR BLOWOUTS 13-1

14 REPORT ON DEVELOPMENTS SINCE THE RELEASE OF THE PHASE 2 REPORT 14-1
14.1 Introduction 14-1
14.2 Recommendations in the Phase 2 Report 14-1

APPENDICES

Appendix 1 GLOSSARY OF TERMS A1-1

Appendix 2 LODGEPOLE BLOWOUT INQUIRY – TERMS OF REFERENCE A2-1

Appendix 3 THOSE WHO APPEARED AT PHASE 1 OF THE INQUIRY A3-1

Appendix 4 POSITIONS OF THE PARTICIPANTS A4-1

Introduction A4-1
Amoco Canada Petroleum Company Ltd. A4-1
Nabors Drilling Ltd. A4-4
Staff of the Energy Resources Conservation Board A4-5
Government Departments A4-6
The Public Advisory Committee of the Environment Council of Alberta A4-9
Pembina Area Sour Gas Exposures Committee A4-10
Canadian Institute of Public Health Inspectors A4-11
Edmonton Area Respiratory Patients A4-11
Health Unit Association of Alberta A4-11
Alberta West Central Health Unit A4-12
Environmental Law Centre A4-12
Mr. C. Sams A4-12
Other Involved Organizations A4-13
The General Public A4-13

Appendix 5 LODGEPOLE BLOWOUT INQUIRY – PHASE 2 REPORT A5-1

Appendix 6 PHOTOGRAPHS OF THE 13-12 BLOWOUT A6-1

Appendix 7 METHOD OF PRESENTING H_2S AIR MONITORING DATA AS USED BY ALBERTA ENVIRONMENT AND AMOCO WHEN OFF-SCALE READINGS WERE ENCOUNTERED BY MOBILE MONITORING INSTRUMENTS A7-1

Appendix 8 GOVERNMENT OF ALBERTA – PEACETIME EMERGENCY OPERATIONS PLAN FOR A SOUR GAS RELEASE A8-1

FIGURES AND TABLES

FIGURES

Page

2.1 Lodgepole – Edmonton Area 2-3

3.1 Chronology of Well-Site Related Activities Prior to, During, and Subsequent to the Blowout of AMOCO DOME BRAZEAU RIVER 13-12-48-12 3-2

3.2 Amoco's Seismic Interpretation of Desired Well Location 3-3

3.3 Drilling Summary from Drilling Out Intermediate Casing Until Blowout 3-5

5.1 Drilling, Blowout Prevention, and Mud Circulation System 5-3

5.2 Likely Wellbore Situation. Core No. 1 5-7

5.3 Likely Wellbore Situation. Core No. 2 5-11

5.4 Likely Wellbore Situation. Core No. 3 5-15

5.5 Amoco's Schematic of Drilling Mud System 5-17

5.6 Estimated Mud Supply at Surface of the 13-12 Well 5-19

5.7 Amoco's Diagram of the "Poorboy" Degasser 5-23

5.8 Amoco's Diagram of the BOP, Rotary Table and Automatic Pipe Stripper 5-27

6.1 Amoco's Diagram of Proposed Installation of BOP (Plan "A") 6-3

6.2 Amoco's Diagram of Proposal to Open BOPs and Let Pipe Drop (Plan "B") 6-5

6.3 Amoco's Diagram of Preparations for Plan "C" Capping Attempt 6-7

6.4 Amoco's Diagram of Unsuccessful Plan "C" Capping Attempt 6-9

6.5 Amoco's Diagram of Casing Stub and Work Sheds 6-11

6.6 Amoco's Diagram of Installation of Final Control Assembly 6-13

6.7 Amoco's Schematic of Planned Relief Well 6-15

7.1 Lodgepole – Cynthia – Drayton Valley Area Showing Residential Locations of PASGEC Panel Members 7-3

7.2 Lodgepole – Edmonton Area Showing Location of Stationary Air Monitors 7-9

7.3 Lodgepole – Cynthia – Drayton Valley Area Showing Recorded Hourly H_2S Concentrations Greater than 10 and 5 ppm at Residences 7-13

7.4 Hourly Maximum H_2S Concentrations in Cynthia 23-24 November 1982 7-15

7.5 Lodgepole – Cynthia – Drayton Valley Area Showing Recorded H_2S Concentrations Greater than 10 and 5 ppm at Residences and the 15 ppm Calculated Isopleths for Flow Rates of 1.4×10^6 m^3 and 2.1×10^6 m^3 Per Day 7-19

8.1 Condensate Distribution Around the 13-12 Well 8-3

8.2 Forest Clearing Area Around the 13-12 Well 8-5

8.3 Boundary of Measurable Sulphur Deposition Around the 13-12 Well 8-7

8.4 Condensate in Soils Around the 13-12 Well 8-11
8.5 Condensate in Groundwater Around the 13-12 Well 8-13

TABLES

5.1 Summary of Time Required (Minutes) During Coring Operations at the 13-12 Well 5-6
5.2 Detailed Drilling Practices While Obtaining Core No. 1 at 13-12 Well 5-6
5.3 Detailed Drilling Practices While Obtaining Core No. 2 at 13-12 Well 5-10
5.4 Detailed Drilling Practices While Obtaining Core No. 3 at 13-12 Well 5-14
7.1 H_2S Concentrations Greater than 10 and 5 ppm Recorded at Residences 7-11
7.2 H_2S Concentrations Recorded in Populated Centres by Stationary Monitors 7-12
13.1 Possible Consequences of Inquiry Recommendations on Lodgepole Incident 13-2

The Lodgepole 13-12 well on fire with rig debris being removed.

Photo credit: W. Wylie, ERCB

1 SUMMARY

INTRODUCTION

17 October 1982 will likely be a significant date in Alberta's history. It was on that day at 14:30 that the well, AMOCO DOME BRAZEAU RIVER 13-12-48-12 (13-12 well), located 20 kilometres (km) west of the small hamlet of Lodgepole, blew out of control. For over 2 months specialists fought to regain control of the well and were finally successful on 23 December 1982.

People residing near the blowout were significantly affected by events during the 67 days. At times, the odours were severe and people feared for their health and safety. Even people far removed from the area were subjected to the unpleasant odours, depending on atmospheric conditions.

The blowout will likely have a significant impact on the Alberta gas industry, particularly with respect to drilling sour gas wells.

A public inquiry was convened to learn what happened, why it happened, and how it might be avoided in the future. The Inquiry Panel's (Panel) views on these questions are provided in this summary.

WHAT HAPPENED AT LODGEPOLE?

In August 1982, Amoco Canada Petroleum Company Ltd. (Amoco) applied to the Energy Resources Conservation Board (ERCB) for a licence to drill a well to be located 20 km west of the hamlet of Lodgepole, Alberta. The well was spudded on 10 August 1982 and was drilled to about 3000 metres (m) without significant incident. Intermediate casing was then installed prior to drilling into the expected productive formation. On 15 October, the drilling crew began coring into the zone and the first two cores were obtained without apparent problems. On 16 October, the crew proceeded with core No. 3, but halted coring operations when evidence of fluid influx from the formation was detected.

For the next 16 hours, the crew fought to regain control of the well but finally, at 14:30 on 17 October, the well blew out of control. In spite of numerous measures to regain control, the sour gas blowout persisted for 67 days with control finally being regained on 23 December 1982.

THE INQUIRY

On 14 January 1983, the ERCB announced that an inquiry would be held to determine the facts surrounding the Lodgepole blowout. The inquiry was held in two phases and this report deals with Phase 1, the analysis, findings, and recommendations regarding the blowout itself.

IMPORTANT ISSUES

As a result of several public pre-inquiry meetings with participants, the Panel determined that the following were the most important issues to be addressed:

> What were the factors contributing to the Lodgepole blowout and what actions were taken to prevent it? Were these actions adequate?
>
> What significant factors contributed to regaining control of the well? Were control actions adequate?
>
> Was there a hazard to human health and, if so, was the effect measurable? What steps were taken to minimize the effect and were the steps adequate?
>
> Was there an impact on the environment and, if so, how serious was it? What steps were taken to reduce the impacts and were the steps adequate?
>
> Were ERCB and Government department regulations, policies, and procedures adequate? Were the responses to the emergency following the blowout adequate?

Additionally, the Panel decided it should examine, quite separately from the 13-12 incident, the more general question of whether further actions should be taken to minimize the possibility of future blowouts in Alberta. That assessment took place following the main inquiry and the Panel's conclusions were provided in its Phase 2 report issued in April 1984.

WHAT WENT WRONG AT THE 13-12 WELL?

The drilling plan for the 13-12 well included cutting cores in the productive formation. While cutting the third core on 16 October, reservoir fluids, including sour gas, unexpectedly entered the wellbore resulting in what the industry calls a "kick". Amoco was unsuccessful in controlling the kick and after a 16-hour battle, totally lost control of the well on 17 October.

Why did the kick occur? Unfortunately, it is not possible to be certain as to all of the developments that occurred on 16 and 17 October. Nevertheless, the Panel's reconstruction of those events leads it to conclude that the initial kick occurred primarily because drilling practices during the taking of cores No. 2 and 3 were deficient and, when combined with the marginally adequate mud density being used, this permitted the entry of reservoir fluids into the wellbore.

The Panel also has concluded that the kick was likely not controlled because

(a) the drilling crew did not immediately recognize the problem and therefore did not immediately apply and maintain standard kick-control procedures,

(b) several pieces of vital equipment did not function properly, including:

   (i) casing pressure instruments,
   (ii) the degasser,
   (iii) drill pipe, and
   (iv) travelling block hook latch, and

(c) supplies of mixed drilling mud were not adequate during the kick-control operations.

In summary, the Panel concludes that no single element in the chain of events was the sole cause of the blowout. The unexpected entry of reservoir fluids into the wellbore was probably due to a combination of Amoco not adhering to sound drilling practices and only marginally adequate mud density. If the degasser had operated effectively, the initial kick might have been circulated out of the system, and subsequent kicks would likely have been avoided. Even with the failure of the degasser, control might have been maintained if there had been sufficient and properly weighted mud on hand to pump into the well. Additionally, if the casing pressure instruments had been operational from the outset, the crew might have recognized the kick at an earlier stage and implemented standard kick-control procedures when fluid influx was still relatively small. If the decision had been made to use hydrogen-sulphide- (H_2S) resistant pipe for the full drill string, the pipe might not have parted and the succession of kicks might still have been successfully circulated out. And finally, if the travelling block hook latch had not failed, it may have been possible to retain control of the well by "top kill" methods.

Were Amoco's actions satisfactory respecting these various developments? Amoco indicated that its program was based, from the outset, on the possibility but not an expectation of encountering sour gas. The Panel is satisfied that Amoco applied reasonable judgement with respect to the selection of the Nabors rig, approving the degasser, and to a lesser degree, in selecting the type of drill pipe to drill the well, even though, with hindsight, the latter two turned out to be inadequate for the conditions that developed. On the other hand, the Panel believes Amoco's actions were deficient with respect to:

(a) drilling practices during coring operations (cores No. 2 and 3),

(b) implementation of standard kick-control procedures,

(c) ensuring adequate mixed drilling mud was available at all times, and

(d) maintaining equipment in satisfactory operating condition (casing pressure instruments).

It appears to the Panel that the fundamental problem was that Amoco did not apply the necessary degree of caution while carrying out operations in the critical zone. Amoco did not appear to be sufficiently aware of the potential for problems that could occur when coring into the porous zone and thus the need to be fully prepared in the event of a fluid influx. Consequently, when a kick developed, there were delays in responding to it. Then, when equipment problems occurred and supplies of mixed mud were inadequate, Amoco was forced into further delays of precious time in implementing kick-control actions.

In summary, it is clear to the Panel that the major area of deficiency relates to the "human factor" which was so extensively referred to during the Phase 2 portion of the inquiry.

The Panel has made a series of recommendations aimed at reducing the possibility of future blowouts. Several have already been implemented, or are being studied. Anyone interested in the detailed assessment of the cause of the blowout, or the Panel's specific recommendations, is invited to review section 5 of this report.

REGAINING CONTROL OF THE 13-12 WELL

It required 67 days to regain control of the 13-12 well. Why did it take so long?

The Panel believes that several factors were instrumental in the delay:

1 The well was particularly difficult to tame.

The flow rate from the well was much higher than originally estimated. Also, the flow contained large volumes of condensate and a high percentage of H_2S, both of which became serious inhibiting factors to regaining control. Indeed, the Panel believes it would be difficult to find a more serious and difficult blowout to control.

2 Weather conditions were frequently unfavourable.

Because of the high flow rate from the well, and its high H_2S content, work on the well was possible only when there was sufficient wind to disperse the gas. Frequently, atmospheric conditions were relatively calm, and for more than 8 days out of the 26 days that the well was not on fire, weather conditions at the well site prevented the control crews from working.

3 Amoco's safety procedures and equipment, while appearing to be typical for the industry, were not adequate to cope with the magnitude and type of emissions from this particular well. As a result, a serious accident interrupted an operation that might have been successful with a less difficult well, and resulted in a further well control delay of 37 days.

Initially, Amoco and the ERCB had concluded that only two well control options were available: capping the well while it was not on fire, or drilling a relief well. Since the relief well would take up to 3 months to drill, with no assurance of success when completed, it was judged to be a last resort. After Amoco and the ERCB became aware of the damage to the casing bowl from the second fire and significant effects that the sour gas well emissions seemed to be having on the general public, consideration was given to a third control option, capping the well while it was on fire. Evidence at the inquiry indicated that this technique had been used only six times worldwide, and only on wells that were much smaller "blows" than the 13-12 well. While both Amoco and the ERCB recognized the serious risks inherent in this procedure, it was nevertheless selected because of the special circumstances. It eventually proved successful, but required another 21 days before it could be completed.

The difficulties encountered in regaining control of the 13-12 well, and the resulting impacts on the public, amply demonstrate the need to avoid such situations in the future.Once a well has blown out of control, the options available to the well control crew are limited. One of the benefits from the 13-12 experience was to learn that such a difficult well could be brought under control while it was on fire.

HAZARD TO HUMAN HEALTH

How did the emissions from the well affect the health of people residing in nearby regions?

The Panel heard evidence from 30 local residents, members of the Pembina Area Sour Gas Exposures Committee (PASGEC) at the formal inquiry, and 11 residents at the informal session, describing how the blowout had affected the health of members of their families. These effects were said to include headache, eye irritation, upper respiratory tract symptoms such as sore throat, nasal irritation, and nosebleeds in children, and lower respiratory tract symptoms, including pain on deep inhalation and some shortness of breath. The Panel also heard evidence from the Edmonton Area Respiratory Patients. Several of the PASGEC witnesses also referred to a similarity in the symptoms of illnesses in both people and livestock.

Various interpretations were placed on these submissions. Some participants at the inquiry contended that the problems related to a "flu epidemic", others to psychologically induced reactions. Others claimed that the noxious gas was the cause.

Unfortunately, there was a lack of scientific data available for analysis. Considering the large amount of circumstantial evidence, however, the Panel is satisfied that the well emissions did lead to at least short-term health effects for a substantial number of people, particularly in the Lodgepole area. The anecdotal evidence also strongly suggests that some people, especially those having respiratory problems, are much more likely to suffer unfavourable effects from H_2S gas.

What steps were taken by Amoco and Government agencies to protect the health and safety of persons living in the local area?

Although it was not set out in a single document, a protection plan was put in place which provided for:

(a) the establishment of a set of H_2S exposure limits designed to safeguard human health,

(b) the monitoring of actual H_2S concentrations throughout the area where people were residing, and

(c) arrangements for people to leave the area whenever H_2S concentrations exceeded the exposure limits. Where evacuation was deemed not practical, such as in Drayton Valley, the plan called for ignition of the well if H_2S concentrations exceeded the prescribed limits.

Exposure Limits

The protection plan was designed to ensure that if an H_2S concentration of 15 parts per million (ppm) was reached in any area where people were residing, then they would leave the area. Additional standards were identified for persons described as "sensitive", which generally was taken to mean persons with respiratory problems, very young children, the elderly, and pregnant women. However, for various reasons, these additional standards, while acknowledged, were not actually applied.

The appropriateness of the H_2S exposure limits was extensively debated at the inquiry. Particular concern was expressed about the need for much stricter standards for those persons judged to be more susceptible to H_2S.

The Panel recognizes the concerns about the standards, particularly regarding more stringent standards for sensitive people, and has recommended that this matter be given further consideration by the Provincial Board of Health (PBOH).

Monitoring H_2S Concentrations

The air monitoring program to determine actual H_2S concentrations in the general Lodgepole area was under the direction of Alberta Environment (AE). Stationary air monitors were installed in the nearby communities of Cynthia, Lodgepole, and Drayton Valley, and at the Brazeau Dam. Five mobile air monitors, four of them operating 24 hours per day, were used to check rural areas. Under the plan, three of the mobile monitors followed the highest H_2S concentrations as the plume moved through the area.

The monitoring data gathered during the event shows that the dispersion of the gas cloud from the well was actually quite rapid, notwithstanding the large volumes of H_2S gas being emitted. For example, no concentrations in excess of 10 ppm were found at any residences located farther than 20 km from the well, and there were only a few instances inside that 20-km radius. The highest concentration recorded at Cynthia was 14 ppm, at Lodgepole 14.5 ppm, and 5 ppm at Drayton Valley, some 45 km from the well. The highest reading in Edmonton was 0.5 ppm.

Throughout the 26-day period that the well was not on fire, H_2S concentrations were generally low. For example, at Lodgepole, the concentrations were less than 1 ppm for 87 per cent of the recorded hours, while at Cynthia and Drayton Valley they were less than 1 ppm for about 95 and 96 per cent of the time, respectively. In Edmonton, though the odour was detected, the H_2S concentrations were actually less than 0.1 ppm for 93 per cent of the time.

Evacuation

There were six occasions during the 26-day period that the well was not burning when concentrations at local residences reached the evacuation level of 15 ppm. All of these cases were in rural areas. Where they occurred, the people were notified and they left the area on a temporary basis. Additionally, Amoco advised that it was prepared to pay the costs for people who wished to leave the area because of effects from the emissions. A total of 28 individuals plus 4 families left on the basis of the Amoco offer.

IMPACT ON THE ENVIRONMENT

How serious was the environmental impact from the well emissions?

During the 67 days the well was out of control, there were daily emissions to the atmosphere of 150 to 450 tonnes of sulphur and 300 to 1100 cubic metres (m^3) of condensate. For the 26 days the well was not on fire, the condensate fell on the area immediately surrounding the well site and had an impact that was initially like that of an oil spill. Subsequent fires caused the lease area to be extensively burned. While this destroyed vegetation over a large area, it reduced long-term condensate pollution problems. During the period the well was on fire, the sour gas and condensate was combusted in the extremely intense fire and the H_2S was converted to sulphur dioxide (SO_2).

Obviously, emissions of that magnitude are certain to have some environmental impacts. Several studies were made to evaluate the extent of the impacts and the results were submitted to the inquiry. An area of some 300 hectares (ha) surrounding the well was the most seriously affected. There were major impacts on vegetation and soils in that area and minor impacts on surface water, groundwater, benthic organisms, mammals, and birds. Some of these impacts were ameliorated by quick remedial action. Due to the presence of residual condensate on the vegetation outside the burned and cleared areas and in the ground right around the well, there will continue to be impacts near the well site for some years on trees, groundwater, and soil.

To overcome the major impacts in the vicinity of the well, a program of short-term remedial measures and longer-term reclamation has been established. The program is comprehensive and should permit successful rehabilitation of the impacted area.

Sulphur emitted from the well, primarily in a gaseous form, was eventually deposited in low concentrations on the ground over an area of hundreds to thousands of square kilometres. There is no evidence that these levels of sulphur deposition will have long-term harmful effects on soils, vegetation, or water bodies.

RESPONSES BY ERCB AND GOVERNMENT DEPARTMENTS

Were ERCB and government regulations fully complied with during both the drilling and control operations at the 13-12 well?

Were the responses by the ERCB and Government departments appropriate during the emergency especially in terms of protecting the public?

The Panel did not find any evidence that Amoco had, in any significant manner, contravened either ERCB or government regulations. However, it did find that those regulations and policies need strengthening in several areas as they relate to the drilling of critical sour wells.

The Panel has made specific recommendations in several sections of this report to achieve that objective.

The Panel concluded that the response by the ERCB and Government departments was generally adequate, although improvements could be achieved particularly in the co-ordination of emergency response activities. A glaring deficiency by all parties related to communication with the public and the media during the blowout period. It was generally conceded by participants that efforts in this respect had been unsatisfactory and that major improvements were needed. The Panel believes that many of the problems relating to the public, that occurred during the incident, were directly attributable to inadequate communication. The Panel has recommended that a specific communication program be developed so that, in the event of another incident, the public can be kept properly informed and can have its concerns more effectively addressed.

WHAT ABOUT THE FUTURE?

One of the objectives of the inquiry was to identify actions which might be taken to significantly reduce the possibility of a future "Lodgepole". In order to consider that question, the Panel arranged for a separate phase of the inquiry (Phase 2) to consider evidence from drilling industry experts on how blowouts might be reduced. That phase resulted in a substantial number of recommendations by participants, most of which the Panel endorsed in its Phase 2 report, and which the ERCB is pursuing in conjunction with industry. Several of those recommendations are already in effect, although some are on a preliminary or trial basis only.

In its two inquiry reports, the Panel has made many recommendations that relate to drilling, well control, and impacts on the public. The important question is whether those recommendations, if implemented, would significantly reduce the likelihood of future blowouts. To test that proposition the Panel has, in section 13, reconstructed the 13-12 case, but has assumed that its various recommendations were in place and operating effectively prior to the licensing of the well.

From its test of this proposition, the Panel is reasonably certain the 13-12 blowout could have been avoided. Implementation of the Panel's recommendations can significantly reduce the number of blowouts in Alberta, provide some assistance in regaining control of any well where a blowout has occurred, and would play a major role in assisting the public during a blowout. Obviously, major attention should be directed to avoiding blowouts. To that end, the Panel's recommendations include changes in equipment, changes in procedure, and the strict observance of prescribed or accepted operating practices. Particular emphasis needs to be placed on the "human factor" which appears to be a root cause of blowouts. The Panel believes that an effective means of reducing the impact of human factor problems would be to require that operations in the critical zone be conducted in a very cautious and careful manner. To achieve that objective will require the commitment and direction of senior management of those companies drilling critical sour wells. The ERCB can assist by strengthening its inspection procedures and regulatory requirements.

CONCLUSION

The Panel's findings indicate that the 13-12 blowout could probably have been avoided, even allowing for equipment failures, if Amoco had followed a policy of cautious drilling in the critical zone and if Amoco had been better prepared to deal with unexpected developments. The public was understandably concerned, frightened, and angry about the blowout. Two workers lost their lives, and the public experienced widespread and unpleasant health effects. While the evidence suggests to the Panel that the actual long-term physical effects were relatively minor, the legacy of the Lodgepole blowout will permeate the Alberta scene for many years. This is a matter that will require special attention by industry, the ERCB, and Government departments. Special efforts must be made by all parties to avoid another occurrence, if at all possible, and to more effectively handle events should another major well blowout ever occur.

The Panel has made many recommendations that, if fully implemented, can significantly reduce the number of blowouts. Special emphasis has been placed on critical sour wells. Several of the recommendations relate to a review of drilling equipment, but the primary emphasis has been placed on the need to reduce blowouts caused by human error. The Panel has reviewed the inquiry reports issued earlier this year for the blowout at the SHELL ET AL UNIACKE G-72 well[1], off the east coast of Canada, and the loss of the Ocean Ranger[2] drilling rig. It also has reviewed the previous ERCB report on the blowout of the well, AMOCO PACIFIC BRAZR 7-10-48-12 (7-10 well), which occurred in the same area only 5 years prior to the 13-12 blowout. Each of these three reports indicates that a combination of equipment and human factor causes were responsible for the failures. In each case, the relevant inquiry panel, either directly or indirectly, indicated that the failure probably would not have occurred had appropriate practices been followed, notwithstanding the equipment problems. These conclusions are very similar to those for the 13-12 well.

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[1] Report of Investigation of Events Culminating in a Blowout of Gas and Condensate at Shell Et Al Uniacke G-72.

[2] Royal Commission on the Ocean Ranger Marine Disaster – Report One.

The question, then, is how can human factor problems be significantly reduced in drilling operations? The Panel believes that the most effective way would be to ensure that drilling personnel:

(a) are well trained,

(b) are at all times conscious of potential problems, and ready to deal with them,

(c) are properly supported by technical assistance,

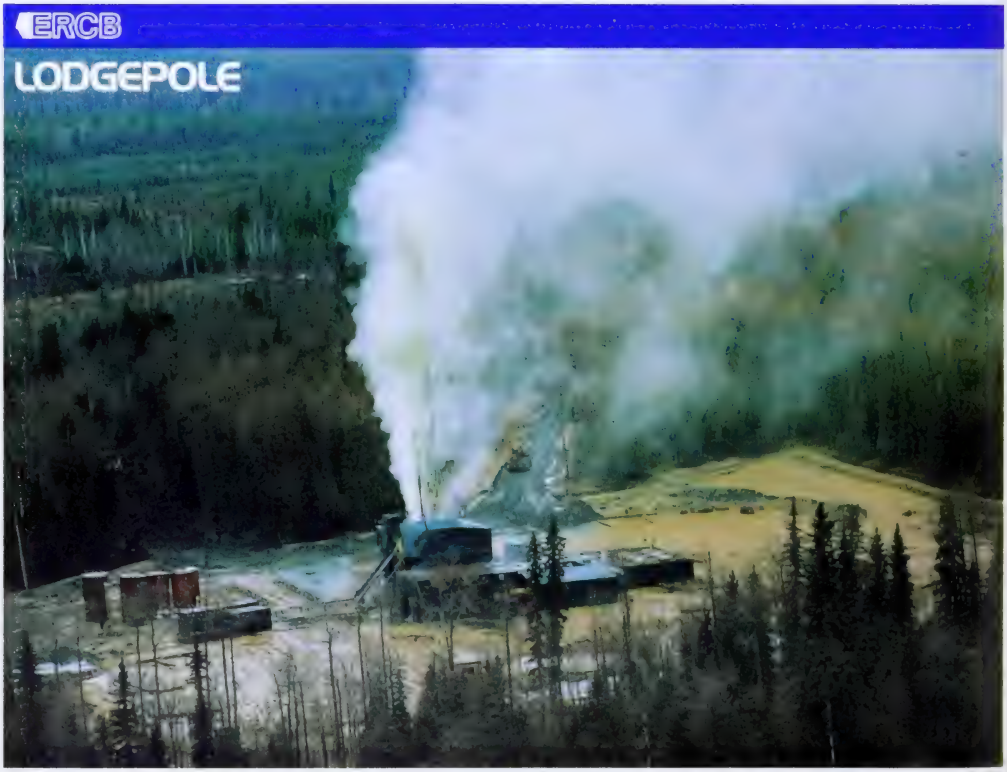
(d) follow a sound and safe drilling plan, and

(e) proceed with operations in a cautious manner, particularly while operating in critical zones.

The primary responsibility for ensuring that these objectives are achieved lies with industry and, in particular, with the company that has been issued a licence to drill. Several of the Panel's recommendations address these issues.

The Panel also believes that the ERCB has a responsibility to test whether these objectives are being achieved, and in that regard believes that the ERCB inspection system should be carefully reviewed to determine how it can be strengthened to minimize human factor problems.

2



The 13-12 blowout prior to the first fire.

*Photo credit:
W. Wylie,
ERCB*

2 INTRODUCTION

2.1 Background

The 13-12 well, located in legal subdivision 13 of section 12, township 48, range 12, west of the 5th meridian, 20 km west of the hamlet of Lodgepole, Alberta, blew out of control from 17 October 1982 to 23 December 1982, a total of 67 days. Figure 2.1 shows the location of the blowout[1] relative to Lodgepole and other communities in the general area. The area near the well and especially to the south and west is sparsely populated and almost entirely forest. The hamlets of Cynthia and Lodgepole, approximately 20 km to the northeast and east, have populations of about 70 and 160, respectively. The area between the well and the communities is almost entirely forest with a few residences near, and to the northwest of, Lodgepole. There are a few occupied oil and lumber industry operations within a 20-km radius of the well.

To the east of Lodgepole, the farming population increases and Drayton Valley, with a population of about 5000, is approximately 45 km east of the well. The City of Edmonton, with a population of about 560 000, is 130 km to the east.

On 14 January 1983, the ERCB announced that an inquiry would be held "... to determine the facts surrounding the Lodgepole gas well blowout ...".

2.2 Preparations for the Inquiry

Three public pre-inquiry meetings were held to discuss arrangements for the inquiry, the funding of participants, the terms of reference, and the rules of procedure. The terms of reference, shown in Appendix 2, were issued on 5 May 1983. To ensure adequate notice of the inquiry was given to the public, and to provide an adequate opportunity for the public to participate, the Panel widely publicized the pre-inquiry meetings, the inquiry, and the informal sessions of the inquiry.

The Panel, through the ERCB, funded the participation of several groups, the preparation of several submissions and studies, and funded or provided assistance from legal counsel where such was warranted.

2.3 Procedural Decisions

The inquiry was separated into two phases, the first to deal specifically with the blowout of the 13-12 well, and the second to consider the general question of drilling industry practices in relation to blowout prevention, especially when drilling for sour gas. It was decided to conduct separate registrations of participants for Phase 1 and Phase 2, to hold separate final arguments, and to issue separate reports. The Panel also decided there would be one continuous record for both phases of the inquiry and as a result, evidence filed and heard in Phase 1 would, where appropriate, apply to Phase 2, and vice versa.

2.4 The Inquiry

The Panel consisted of V. Millard, Panel Chairman, and Panel Members, G. J. DeSorcy, P.Eng., F. A. Herbert, M.D., J. W. Markham, M.B., N. A. Strom, P.Eng., and R. S. Weaver, Ph.D.

Messrs. Millard, DeSorcy, and Strom are members of the ERCB. Dr. Herbert is specialized in pulmonary medicine and is an Associate Clinical Professor of Medicine at the University of Alberta. Dr. Markham is experienced in occupational health and is Clinical Professor, Department of Community Health Sciences at the University of Calgary. Dr. Weaver has experience in biophysical and biomedical research and is the Executive Director of the Alberta Environmental Centre in Vegreville.

The formal portion of Phase 1 of the inquiry was held from 1 November 1983 to 15 February 1984. It took place in the town of Drayton Valley except for a sitting on 9 December 1983, which was in Edmonton. Informal sessions of the inquiry were held in Drayton Valley and Edmonton in the evenings of 23 November and 8 December 1983, respectively. Phase 2 was held from 20 February 1984 to 2 March 1984 in Calgary.

2.5 Participants at Phase 1 of the Inquiry

Amoco, the holder of the licence for the well, and Nabors, the drilling contractor for Amoco, were participants in the inquiry.

The government agencies participating were the ERCB staff, several departments of the Alberta Government, the County of Parkland, the Town of Drayton Valley, the Alberta West Central Health Unit, and the RCMP.

Representation of local public concerns was provided by members of PASGEC, a group comprised of 168 citizens living in the area of the blowout. Environmental concerns were represented by the Public Advisory Committee to the Environmental Council of Alberta, and by the Environmental Law Centre. Representation of public health concerns was provided by the Alberta West Central Health Unit, the Health Unit Association of Alberta, and the Canadian Institute of Public Health Inspectors.

The City of Edmonton and the Edmonton Board of Health were represented, as were a group of respiratory patients from the Aberhart Centre in Edmonton, the Edmonton Area Respiratory Patients.

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[1] See Appendix 1, Glossary of Terms for definition of technical or unusual terms used in the report.

Mr. C. Sams participated to represent concerns regarding the safety of workers in the drilling industry.

A total of 144 persons representing 21 organizations, and one private individual, participated in the formal portion of Phase 1 of the inquiry. In addition, 17 members of the public appeared on their own behalf at the informal sessions in Drayton Valley and Edmonton. Persons and organizations appearing are listed in Appendix 3. A summary of the views of each participant is provided in Appendix 4.

The Panel appreciates the efforts and contributions made by all participants at the inquiry. They provided the inquiry, and therefore the public, with an in-depth review of the blowout, its cause, and its impacts.

As a result of the varied and comprehensive participation, the disclosure of documents, evidence under oath, and the right of cross-examination afforded to all participants, the Panel was satisfied at the conclusion of the inquiry that it had heard and had available to it all evidence necessary for it to make the findings of fact and recommendations in this report. However, to clarify the evidence, the Panel requested and received additional data, after the inquiry, from Amoco and AE with respect to air monitoring, and from Amoco with respect to mud volumes.

2.6 Phase 1 and Phase 2 Reports

The Panel concluded that several recommendations made by participants at Phase 2 could reduce the possibility of a blowout. Since drilling in the Province is continuing, the Panel decided that the recommendations should be implemented as quickly as possible. It therefore decided to issue the Phase 2 report first and Decision D 84-5 was issued in April 1984. A copy of the Phase 2 report is attached as Appendix 5.

This report pertains to Phase 1 of the inquiry, and additionally reports, in section 14, on the progress to date resulting from the recommendations in the Phase 2 report.

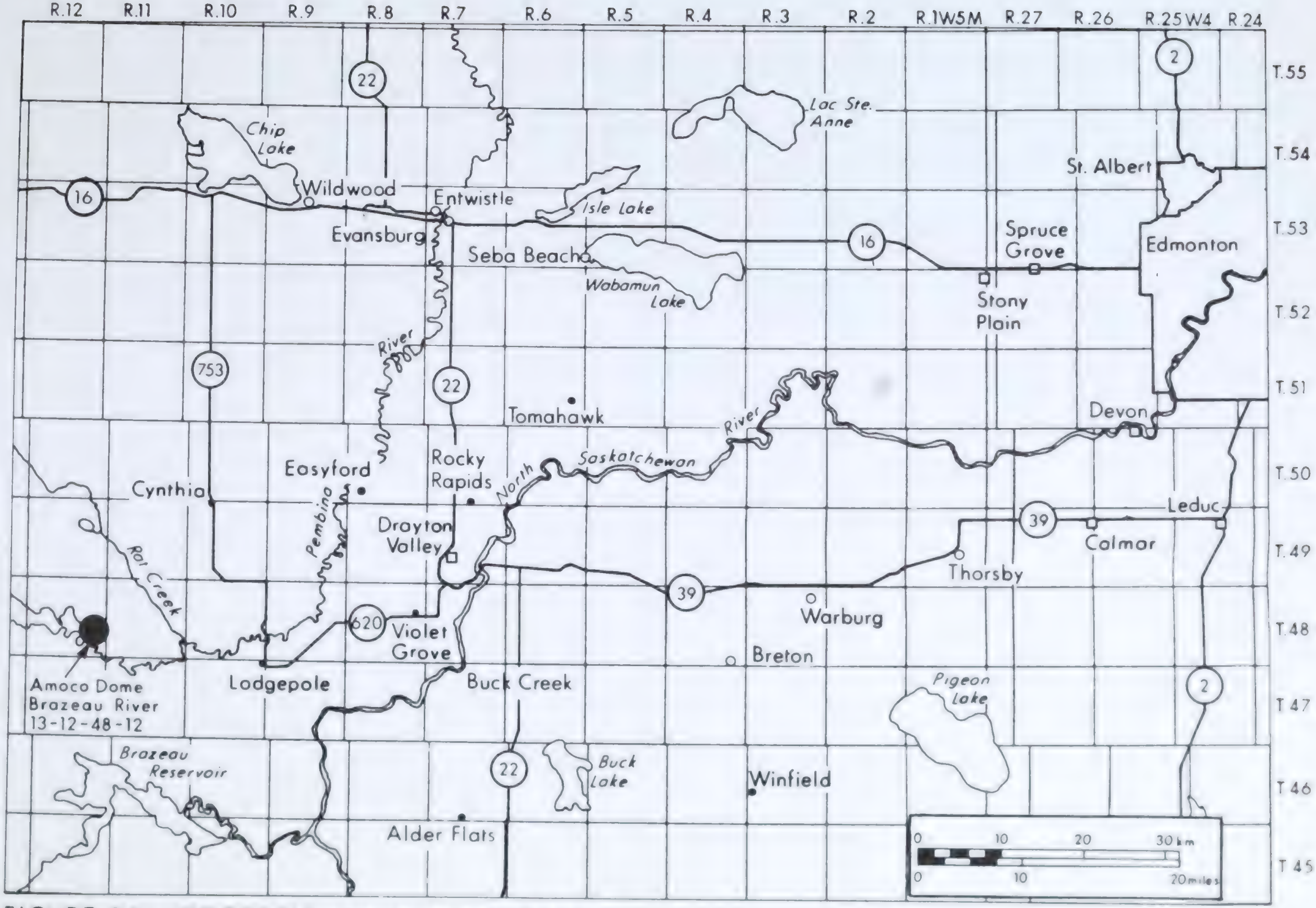

FIGURE 2.1 LODGEPOLE - EDMONTON AREA

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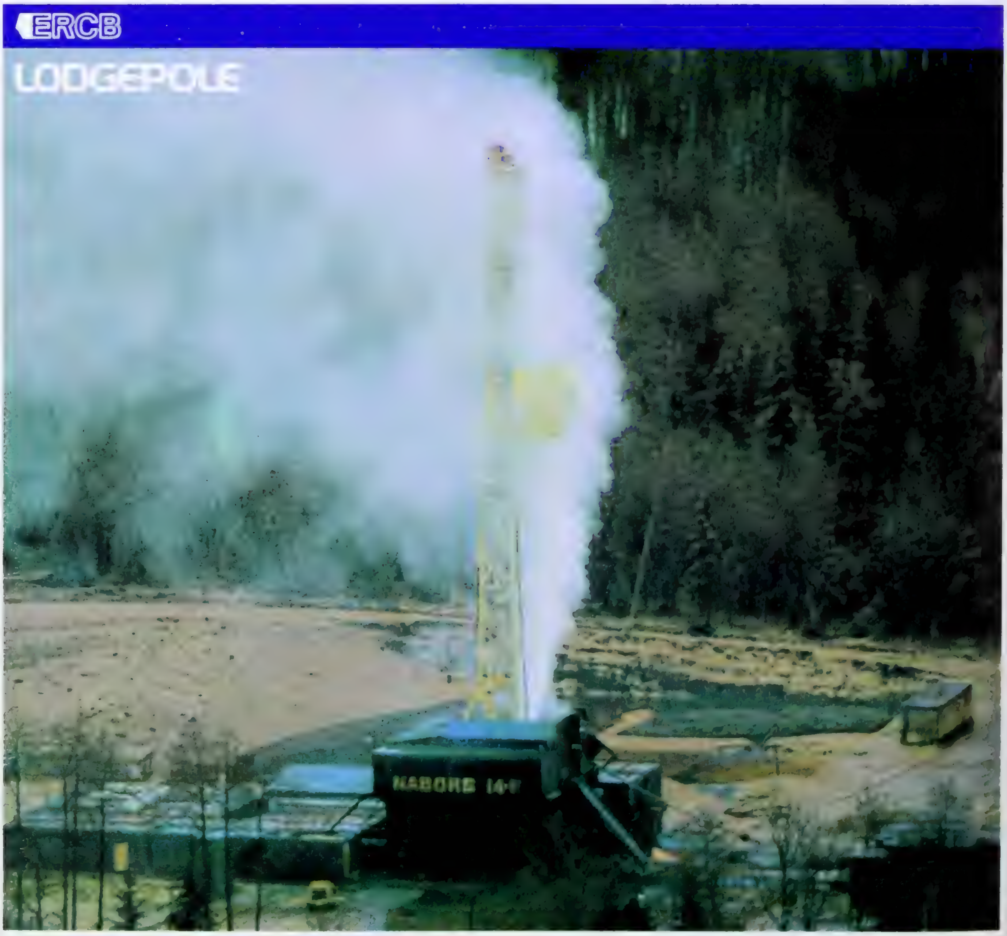


Close-up of the Nabors rig prior to the first fire.

Photo credit: W. Wylie, ERCB

3 A BRIEF REVIEW OF THE ON-SITE ACTIVITIES PRIOR TO AND DURING THE BLOWOUT

3.1 Introduction

This section has been written to give the reader an overview of the events at the well site prior to and during the blowout. An analysis of these events is provided in sections 5 and 6. Figure 3.1 is a corresponding chronology of these events and subsequent related developments.

The 13-12 well is located in the Brazeau Field and was drilled to test a Nisku pinnacle reef that had been identified through seismic work done in the area.

The first well to penetrate one of these prolific reefs was drilled in January 1977. It penetrated what is now known as the Pembina Nisku A Pool at a depth of 3000 m. Since then, over 50 geological structures have been identified and drilled in the general area, known as the West Pembina Nisku play. Reef structures in the vicinity of the 13-12 well fall into two distinct categories:

(1) the pinnacle reef structure, which ranges from a quarter section to more than a section in area and usually contains oil or oil with an associated gas cap generally having a low H_2S content, and

(2) the Meekwap bank, which is a large continuous carbonate bank with a series of coalescing reefs along its fringe. The fringing reefs usually contain gaseous (no oil) hydrocarbons rich in natural gas liquids and H_2S.

On the basis of its interpretation of the seismic data, Amoco expected its 13-12 well to terminate in a pinnacle reef, near to but structurally separated from the bank. This is illustrated in Figure 3.2. Amoco thus expected to find a sweet oil-bearing formation. However, the possibility of encountering sour gas and condensate was recognized and precautions for that eventuality were included in the well program.

3.2 Drilling the Well

Amoco's seismic interpretation required the bottom-hole location of the well to be in Lsd 11 of 12, however, the surface vertically above that location was in an environmentally sensitive area near the Pembina River. To reduce environmental impacts, Alberta Energy and Natural Resources (E&NR) required Amoco to move the surface location to Lsd 13-12. This made it necessary for the well to be directionally drilled.

The 13-12 well was spudded 10 August 1982, using the Nabors 14E drilling rig. Drilling of the surface hole took 3 days, at which time surface casing was run to 330 m and cemented to surface.

The drilling program called for the use of oil-based mud until the intermediate casing was set and a changeover to a water-based mud system for drilling below the intermediate casing. The water-based mud system was to maintain a high pH and contain an H_2S scavenger, iron oxide, to counteract any H_2S that might enter the wellbore.

Drilling continued without significant incident until the intermediate casing depth was reached on 6 October. Over the next 3 days, casing was run to a depth of 3002 m and cemented to at least 120 m above the base of the Belly River. The oil-based mud system was then displaced to a water-based mud as planned. The blowout preventer (BOP) stack and choke manifold were pressure tested to ERCB requirements, a blowout drill was conducted by both the evening and day crews, and on 13 October, the intermediate casing shoe was drilled out.

Figure 3.3 summarizes the drilling activities from 13:00 on 13 October to the time of the blowout as compiled from the evidence and exhibits at the inquiry, particularly Exhibits No. 66 and 66.1.

On 15 October, coring operations began at a depth of 3051 m and mud containing iron oxide was weighted up to 1165 kilograms per cubic metre (kg/m^3) in preparation for the coring program.

3.3 Trouble Begins

The coring program involved using a 20-m-long core barrel assembly with intentions of obtaining 18-m-length cores. Although cores No. 1 and 2 were cut and retrieved with relatively little incident, they had to be broken off short of the 18-m objective because they jammed in the core barrel. The recovered cores were noted to be vugular, ie, highly porous, containing large holes (like swiss cheese), and smelled of H_2S. On 16 October at 16:00 the trip into the hole for core No. 3 began.

Mud weight at the commencement of core No. 3 was 1175 kg/m^3 including 17.5 kg/m^3 of iron oxide. Because of the shortened core length experienced with cores No. 1 and 2, Amoco decided to install a 4-m pup joint to provide for cutting at least 12 m of core No. 3 before making a connection. Coring continued normally from 3063 m but at 3066 m, at 22:50 on 16 October, a Nabors roughneck noticed mud splashing intermittently from the flow nipple. The crew was immediately alerted, circulation was stopped, and a standard flow check was conducted which showed that no flow was occurring. However, the gas count on the mud logger increased sharply and a strong H_2S odour became apparent. The annular preventer was closed to obtain shut-in pressure readings. The shut-in drill pipe and casing pressure gauges both read zero.

FIGURE 3.1 CHRONOLOGY OF WELL-SITE RELATED ACTIVITIES PRIOR TO, DURING, AND SUBSEQUENT TO THE BLOWOUT OF AMOCO DOME BRAZEAU RIVER 13-12-48-12

1981	Oct	Potential Lease Scouted	Planning and Drilling Phase
	Dec	Well Planning Initiated	
1982	Feb	Right of Entry Approved	
	Jul	Drilling Program Formulated	
	9 Aug	Application for a Well Licence	
	10 Aug	Well Licence Issued Well Spudded by Nabors 14E Rig	
	13 Aug	Surface Casing Set	
	10 Oct	Intermediate Casing Set	
	15 Oct	Coring Operations Began	
	17 Oct	Blowout Occurred at 14:30 Emergency Task Forces Mobilized	Loss of Control Phase
	18 Oct	NOTAM (Notice to Airmen) Issued	Well Control Attempts Phase
	19 Oct	ERCB Fire Hazard Order # FH 82-1 Issued Wild Well Control Inc. Personnel Arrived on Location Control Plan A Developed	
	20 Oct	Control Plan B Developed as Contingency Initiated Plans for Relief Well	
	27 Oct	Control Plan A Abandoned Control Plan B Implemented	
	1 Nov	Control Plan B Failed Well Accidentally Ignited	
	4 Nov	Verbal Approval for Relief Well Site	
	8 Nov	Hi-Tower Rig on Standby for Relief Hole	
	14 Nov	Well Fire Extinguished	
	15 Nov	Ministry of Transport Issued Air Space Restriction Order	
	16 Nov	Control Plan C Implemented Accident Occurred – 2 Fatalities	
	25 Nov	Well Accidentally Reignited	
	1 Dec	Control Plan C Abandoned Wild Well Control Inc. Released Boots and Coots Inc. Personnel Arrived	
	4 Dec	Final Control Plan Initiated	
	23 Dec	Well Controlled	Well Controlled
	31 Dec	Environmental Clean-up Initiated	
1983	13 Jan	Hi-Tower 1E Drilling Rig Moved on Location	Well Completion Phase
	24 Feb	Fishing Operations Completed	
	27 Feb	Finished Drilling	
	2 Mar	Production Casing Set	
	4 Mar	Wellhead Installed	
	1 Nov	Phase 1 Commenced	Inquiry
1984	15 Feb	Phase 1 Completed	
	20 Feb	Phase 2 Commenced	
	2 Mar	Phase 2 Completed	
	26 Apr	Phase 2 Decision Report Released	
	18 Dec	Phase 1 Decision Report Released	

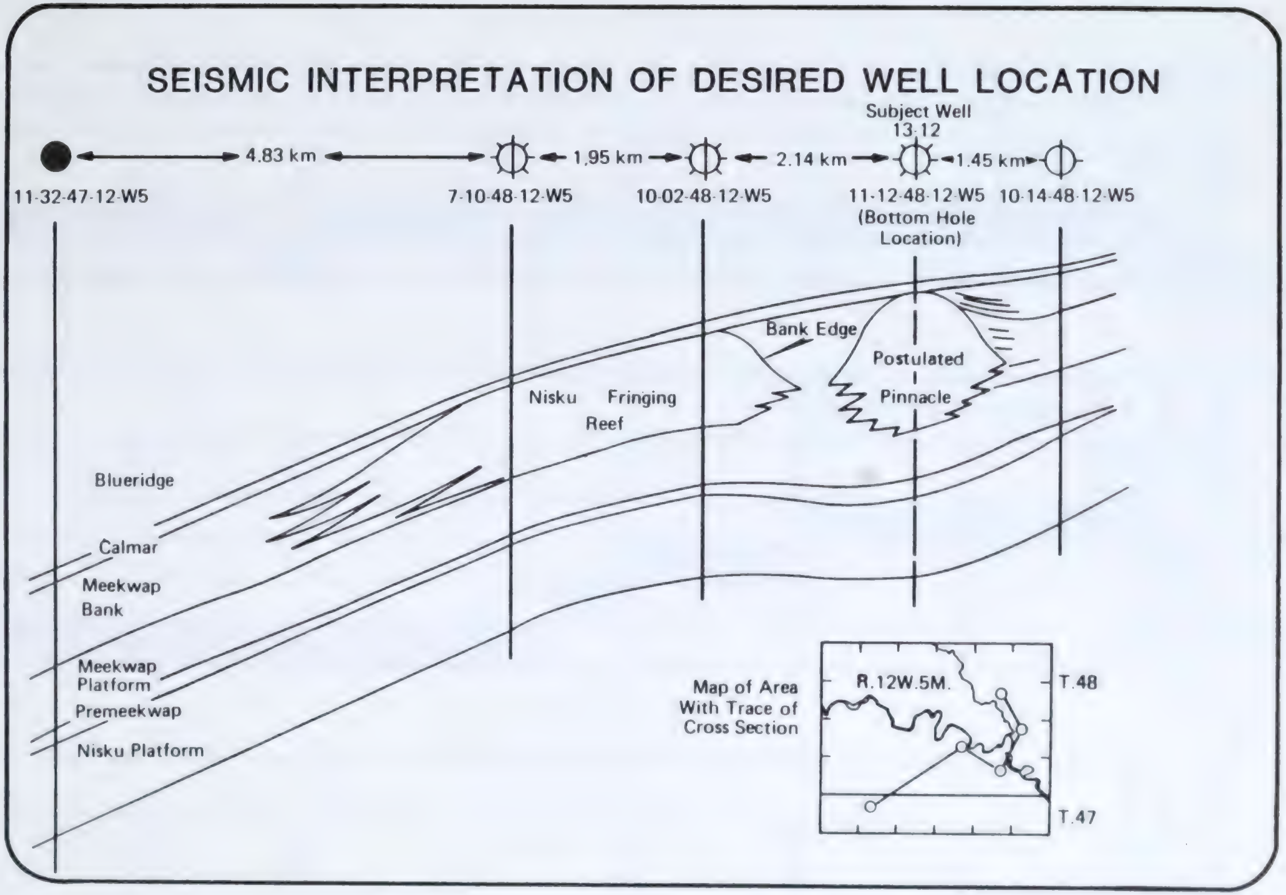


FIGURE 3.2 AMOCO'S SEISMIC INTERPRETATION OF DESIRED WELL LOCATION.
Reproduced from Exhibit No.66.

FIGURE 3.3 DRILLING SUMMARY FROM DRILLING OUT INTERMEDIATE CASING UNTIL BLOWOUT

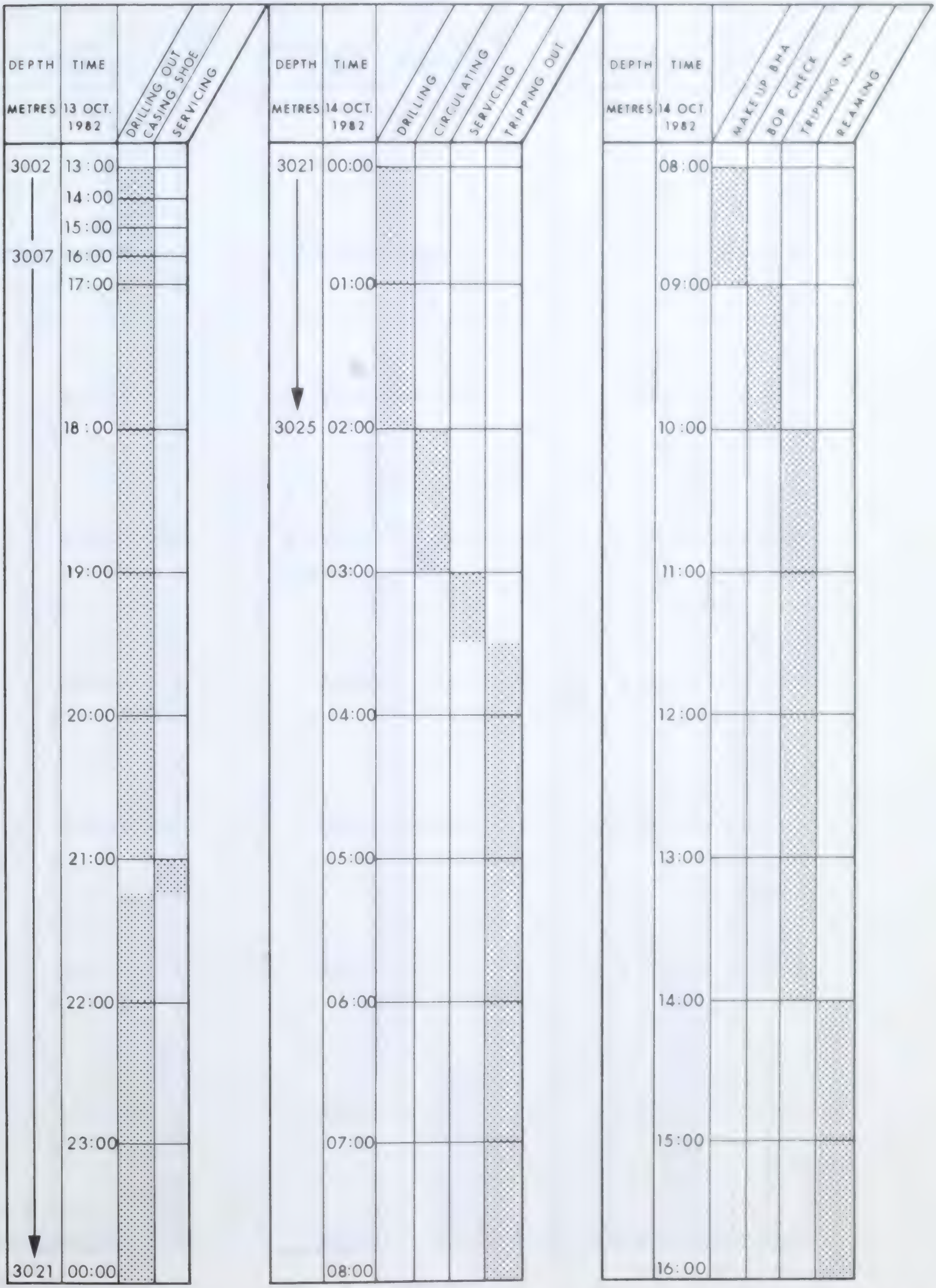


FIGURE 3.3 CONT'D.

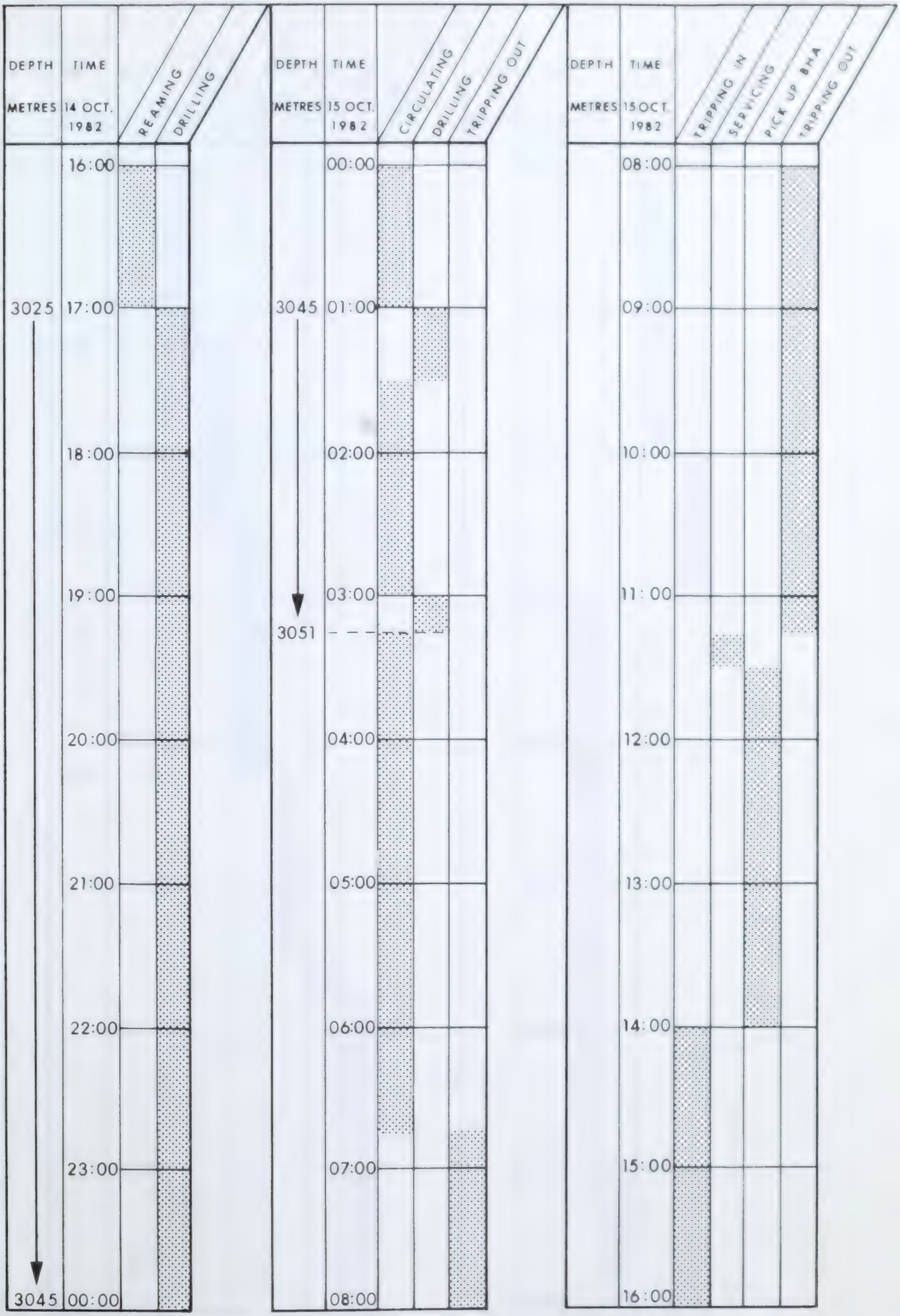


FIGURE 3.3 CONT'D.

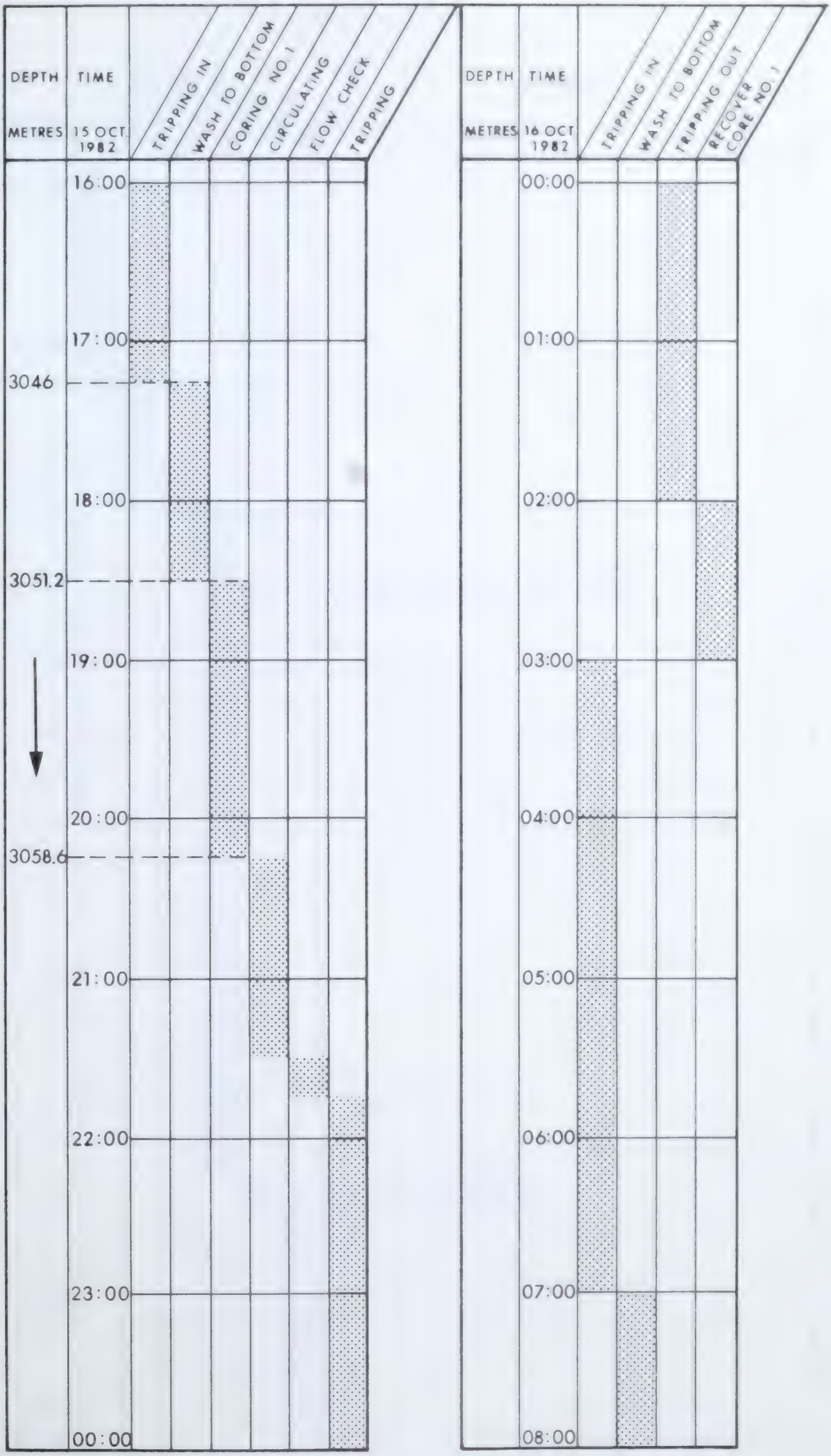
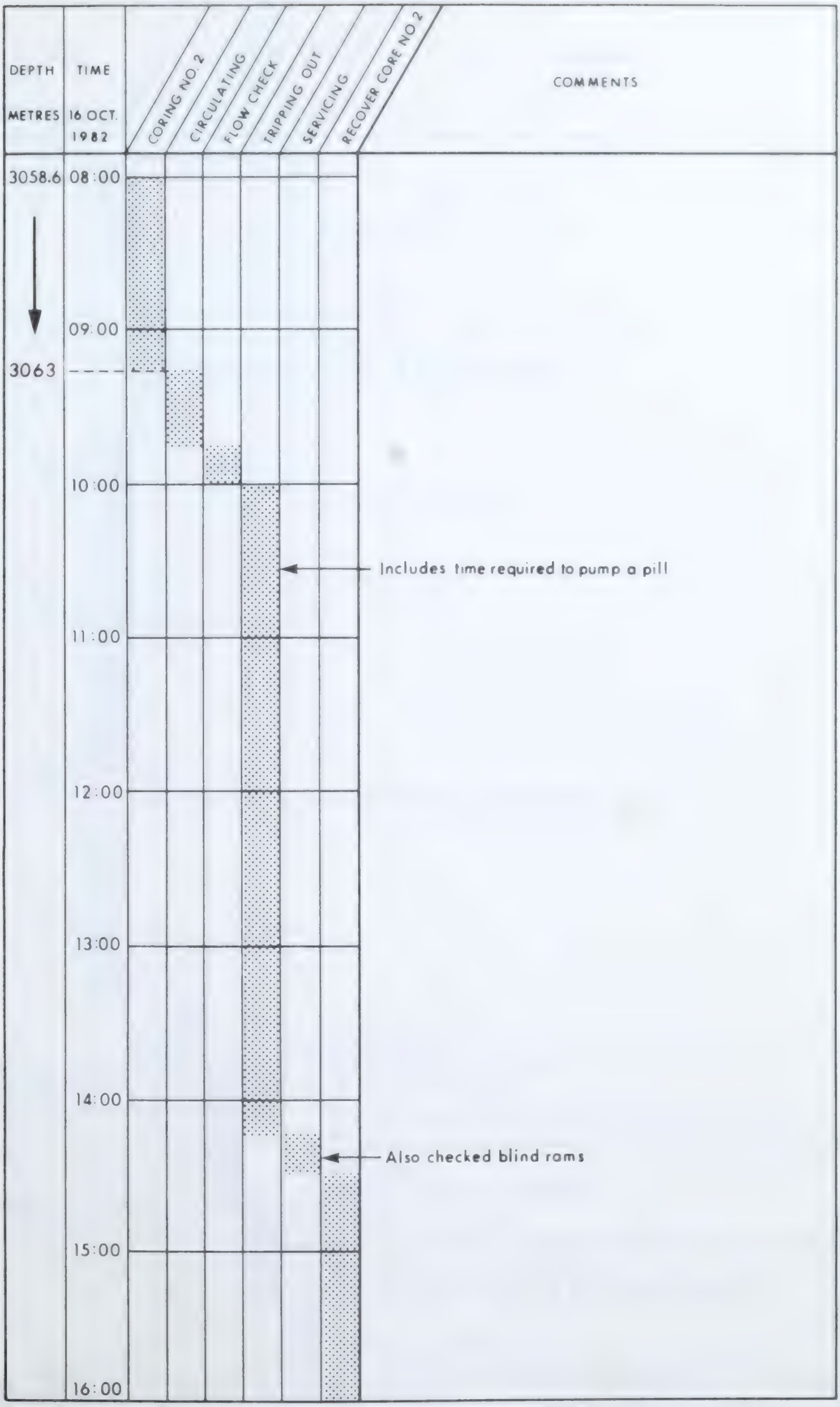


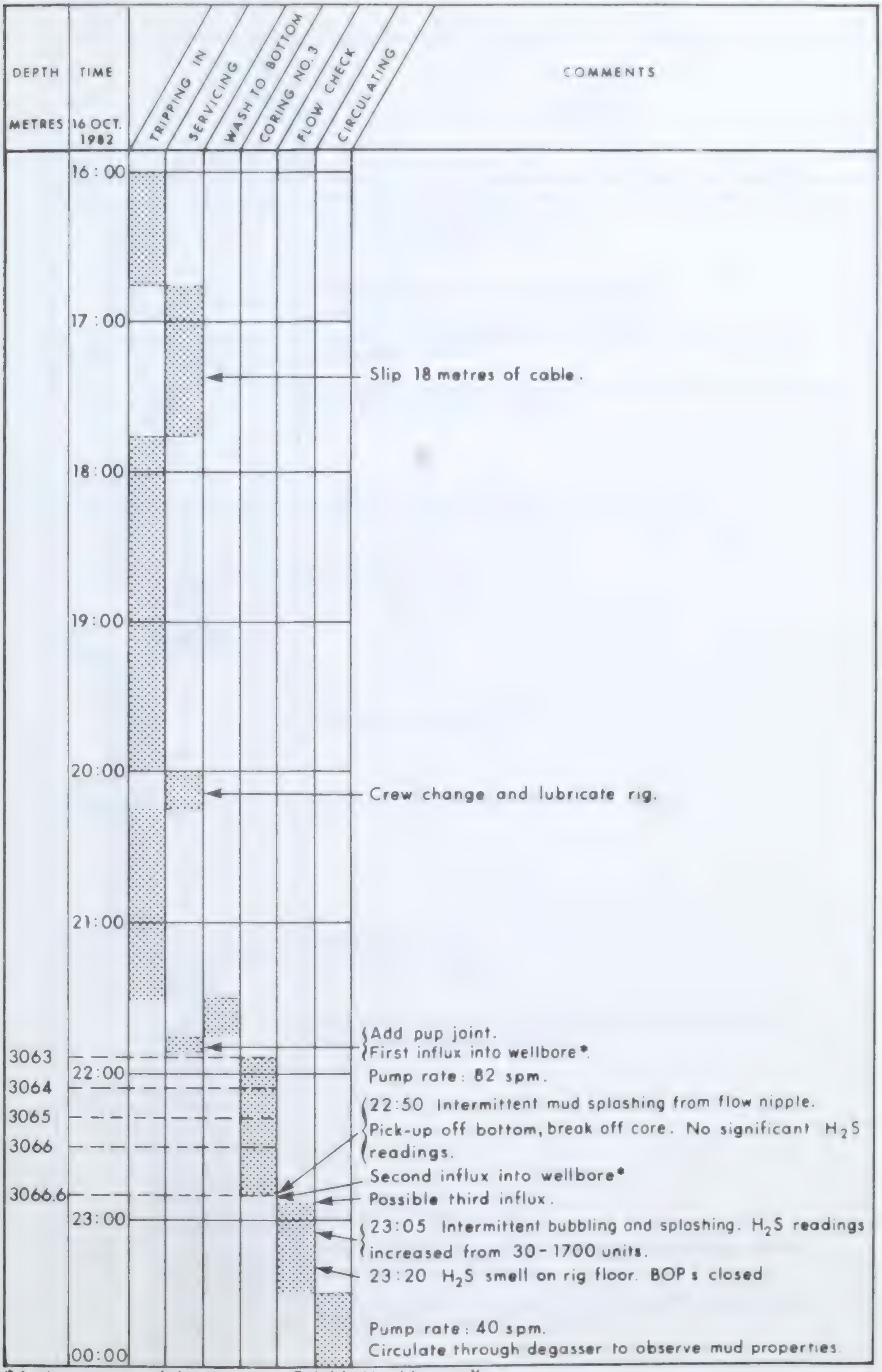
FIGURE 3.3 CONT'D.



Includes time required to pump a pill

Also checked blind rams

FIGURE 3.3 CONT'D.



Slip 18 metres of cable.

Crew change and lubricate rig.

Add pup joint.
First influx into wellbore*.

Pump rate: 82 spm.

22:50 Intermittent mud splashing from flow nipple.
Pick-up off bottom, break off core. No significant H_2S readings.

Second influx into wellbore*

Possible third influx.

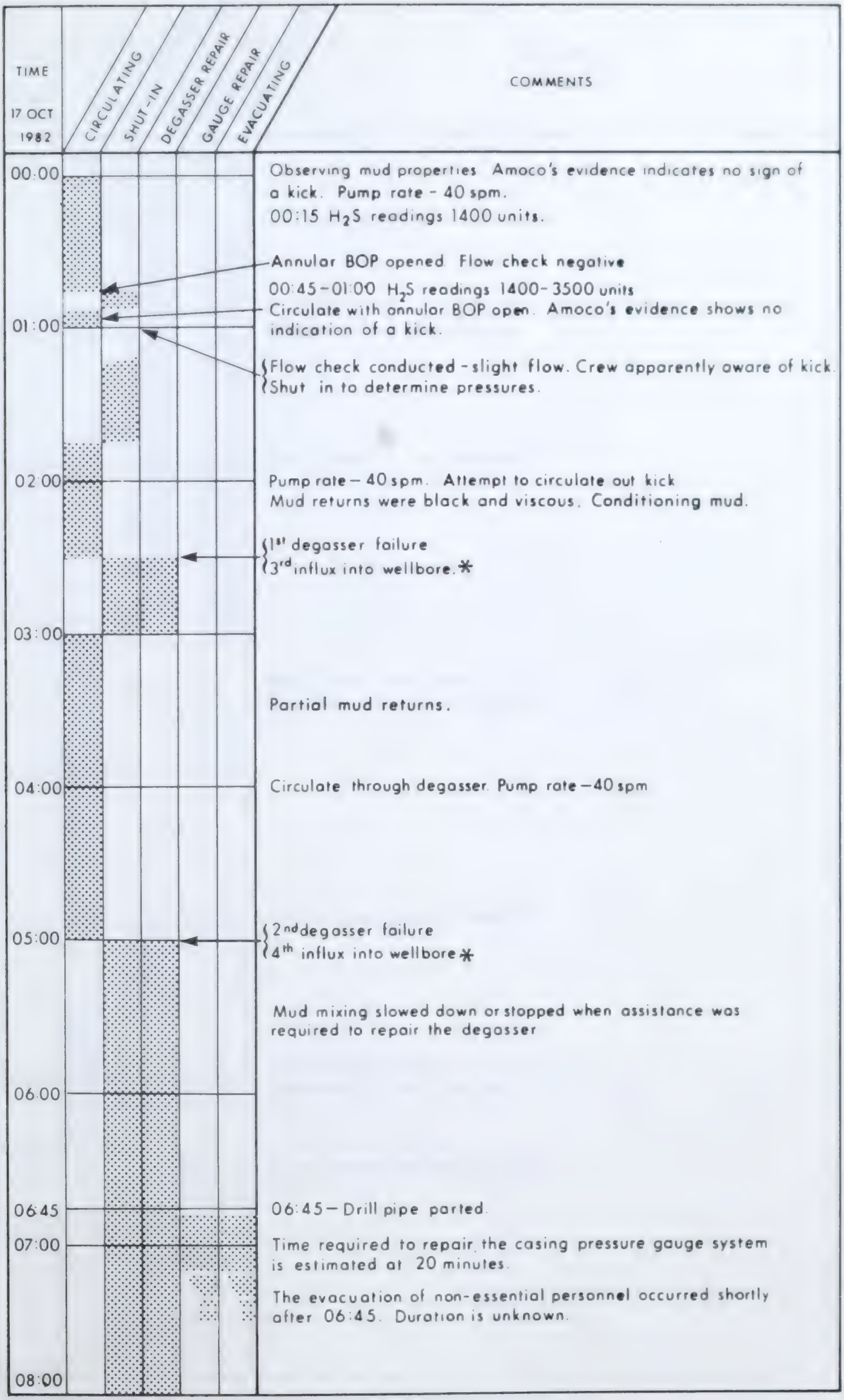
23:05 Intermittent bubbling and splashing. H_2S readings increased from 30 - 1700 units.

23:20 H_2S smell on rig floor. BOP s closed

Pump rate: 40 spm.
Circulate through degasser to observe mud properties.

*As hypothesized by Amoco - Exhibit No. 66 part X.

FIGURE 3.3 CONT'D.



Observing mud properties. Amoco's evidence indicates no sign of a kick. Pump rate - 40 spm.

00:15 H_2S readings 1400 units.

Annular BOP opened. Flow check negative.

00:45 – 01:00 H_2S readings 1400 – 3500 units

Circulate with annular BOP open. Amoco's evidence shows no indication of a kick.

Flow check conducted - slight flow. Crew apparently aware of kick.
Shut in to determine pressures.

Pump rate – 40 spm. Attempt to circulate out kick.
Mud returns were black and viscous. Conditioning mud.

1st degasser failure
3rd influx into wellbore.*

Partial mud returns.

Circulate through degasser. Pump rate – 40 spm

2nd degasser failure
4th influx into wellbore*

Mud mixing slowed down or stopped when assistance was required to repair the degasser

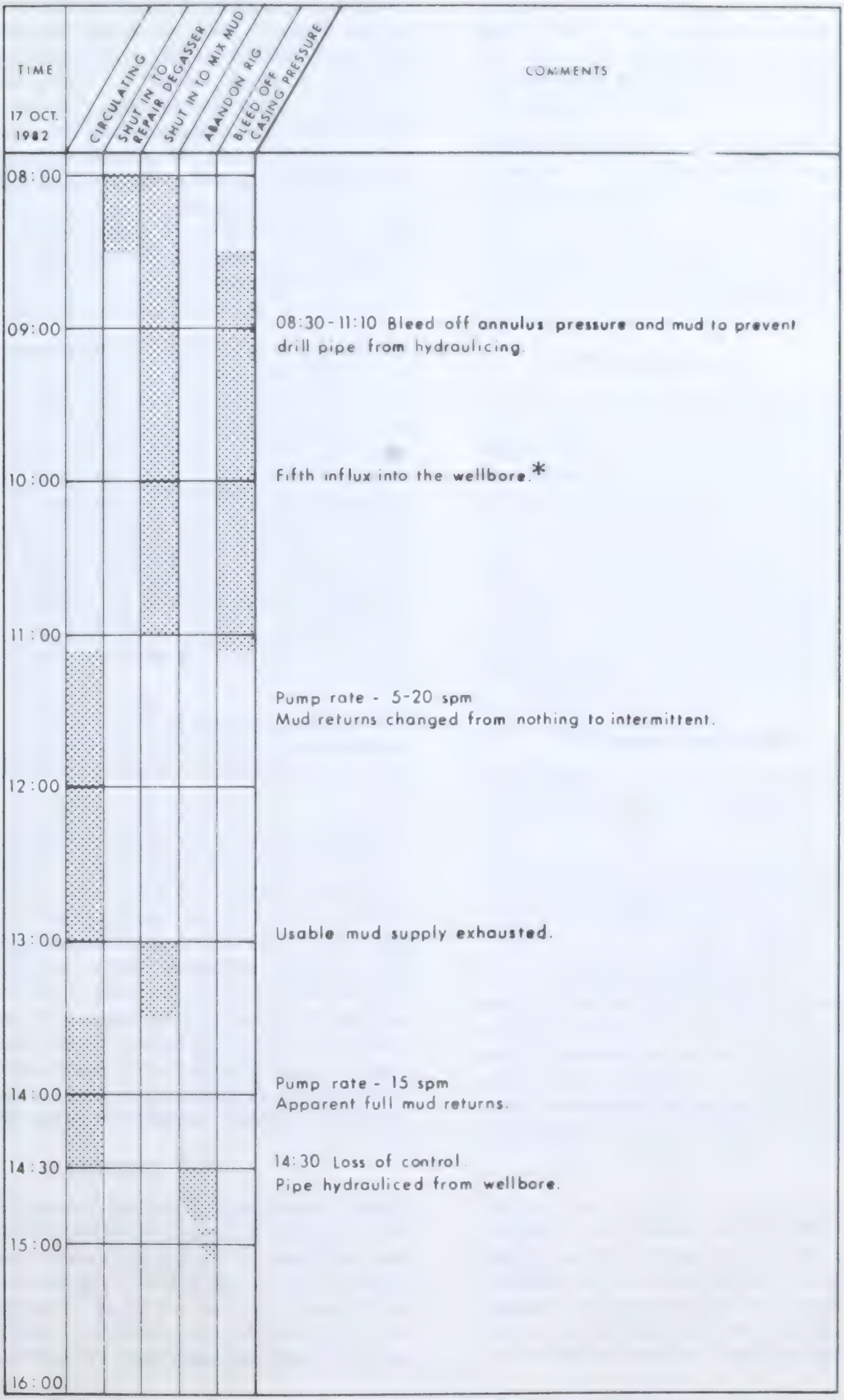
06:45 – Drill pipe parted.

Time required to repair the casing pressure gauge system is estimated at 20 minutes.

The evacuation of non-essential personnel occurred shortly after 06:45. Duration is unknown.

* As hypothesized by Amoco – Exhibit No. 66 part X.

FIGURE 3.3 CONT'D.



08:30 - 11:10 Bleed off annulus pressure and mud to prevent drill pipe from hydraulicing.

Fifth influx into the wellbore.*

Pump rate - 5-20 spm
Mud returns changed from nothing to intermittent.

Usable mud supply exhausted.

Pump rate - 15 spm
Apparent full mud returns.

14:30 Loss of control.
Pipe hydrauliced from wellbore.

*As hypothesized by Amoco - Exhibit No. 66 part X.

At 23:30, with the annular preventer closed, circulation was resumed through the choke manifold and the degasser. Circulation pressure was 2000 kilopascals (kPa). In the early hours of 17 October, circulation was stopped and a flow check again indicated no flow. Conventional circulation, with mud returns direct to the mud tank, was re-established. However, in a short period of time, gas readings increased sharply. A flow check indicated a slight mud flow so the well was shut in to observe pressures. The drill pipe pressure was 2000 kPa and the casing pressure gauge read zero. At 01:45 it was assumed that the casing pressure gauges at both the driller's panel and choke manifold were not functioning.

Circulation through the choke manifold and degasser was resumed at 01:45 until, at approximately 02:30, the degasser failed when the float jammed in its seat. The degasser was repaired by 03:00 and circulation resumed until 05:00 when another surge of mud and gas erupted through the degasser, jamming the float down, puncturing it, and wedging it into its seat. Amoco estimated that 30 m^3 of mud had been lost into the flare pit and on the ground as a result of the failure. At 06:45 the drill pipe suddenly parted. To prevent the remaining pipe from rising out of the hole, the upper pipe rams were immediately closed. The faulty casing pressure instruments were repaired and the casing pressure was found to be 10 500 kPa.

After the drill pipe parted, all non-essential personnel were evacuated from the lease and additional sour gas detection and breathing apparatus was ordered to the location.

By about 08:30 in the morning of 17 October, the degasser had been repaired and by 11:00, mud had been reconditioned. Mud weight had been increased to 1440 kg/m^3 and more iron oxide added. Circulation was resumed. Casing pressure was reduced from 9200 to 7000 kPa through the choke system on the manifold. After circulating for an hour, intermittent mud returns were restored and maintained until, at 13:00, the weighted mud volumes in the suction tank were used up. The well was again shut in to mix a further 25 m^3 of 1350 kg/m^3 mud. During the 30-minute shut-in period, drill pipe and casing pressure remained static at 10 000 kPa. Circulation was resumed and by 14:10 full mud returns were obtained.

3.4 The Blowout

At 14:30, the drill pipe started to hydraulic out of the hole. The driller immediately engaged the draw works and attempted to raise the block and hook ahead of the rising kelly and drill pipe. The drill pipe rose faster, causing the kelly bales to hit the hook latch and the bales fell out of the hook. The upward travel of the drill pipe was arrested when a tool joint lodged against the closed pipe rams. The kelly, now unsupported, fell through the "V" doors on the rig floor bending the drill pipe. The kelly hose broke off at the gooseneck on the kelly swivel and mud and gas began to blow out of the gooseneck. The well was now out of control.

Estimates of the emissions at the time of the inquiry were 1.4 million (10^6) m^3 of gas[1], or 50 million cubic feet per day, containing 23 to 25 per cent H_2S, and 750 m^3 of condensate per 10^6 m^3 of gas or 133 barrels of condensate per million cubic feet of gas. However, during the blowout itself, estimates varied but were somewhat less than the 1.4 x 10^6 m^3, and considerably less with respect to estimates of H_2S.

3.5 Emergency Measures

At 14:30 on 17 October with the well out of control, Amoco initiated action under its "Major Wellsite Incident Response Plan". Key Amoco personnel were alerted and they implemented actions necessary to respond to the blowout. Additional safety personnel, breathing apparatus, paramedics, ambulances, helicopters, and fire protection equipment were contracted for dispatch to the site. Continuous H_2S monitoring equipment was ordered for both on-site and off-site monitoring. Special tools for blowout control were ordered and a control specialist, Wild Well Control Inc. (Wild Well) of Houston, Texas was engaged. Shortly afterwards, the area was closed to all unauthorized personnel by ERCB order.

3.6 Well Control Attempts Begin

On 19 October, the crew of well-control specialists from Wild Well arrived on location. The bent drill pipe protruding above the drilling floor had broken at the bend and fallen away, leaving a 0.3-m stub of drill pipe protruding above the rotary table. Faced with this situation, two alternative control plans were developed. Plan A involved the fabrication of a blind ram BOP on top of a long valved spool. This assembly would be stripped down over the drill pipe stub and attached to the top of the annular preventer. The mud lines would then be hooked to the spool, the blind ram BOP would be closed, and mud would be pumped into the well. On 27 October, after some preliminary preparation, it was determined that the opening in the automatic pipe stripper below the rotary table was too small to allow the passage of the kill spool, the pipe stripper could not be removed because of the drill pipe, and Plan A was discarded.

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[1] The flow rate of the well is unknown. At the time of the inquiry, it was estimated at 1.4 x 10^6 m^3 of gas per day. During the blowout, the flow rate would vary depending on the size of the opening at the surface which changed as the condition of the well changed. The well has been partially tested since that time and indications are that the flow could be substantially higher.

Plan B consisted of opening the BOPs to allow the drill pipe to drop down the hole and then closing the blind rams. Amoco recognized that the drill pipe might be blown out of the hole rather than dropping as planned. After completing some related calculations and assessing the alternatives, Amoco decided to proceed with Plan B.

On 1 November at 14:07, after a previous attempt in the morning had failed, the BOPs were successfully opened. The drill pipe immediately shot out of the hole, striking the monkey board in the derrick and, in a few seconds, the entire location was engulfed in flames. Very shortly afterwards, the rig derrick collapsed.

The next several days were spent cleaning away debris. In the interim, a relief well site was constructed and the possibility of drilling a relief well was re-examined and rejected on the basis of potential risk to the drilling crew and the expectation of an early top kill of the 13-12 well. Nevertheless, a suitable drilling rig was placed on standby and a drilling program was designed.

On 14 November, the well fire was extinguished through the use of explosives and Plan C was attempted. It entailed the removal of the existing intermediate casing spool and installing a new spool and BOP control stack.

On 16 November, a large crane was employed to lift the BOP assembly over the wellhead. During this attempt, an accident occurred which resulted in the death of two Wild Well employees who were overcome by H_2S.

Wind direction, low wind velocities, and ground inversions continued to hamper further activity from 17 to 25 November. Suddenly, at 12:53 on 25 November, a fire started some 60 m southwest of the well and, within minutes, the lease and well were again on fire. It was later determined that the probable cause of ignition was a muskeg fire, more than a metre underground, that had gone undetected.

3.7 Establishing Control of the Well

After the condensate on the lease had been burned, it was discovered that the extreme heat had damaged the well casing, making its integrity suspect. At this time, Amoco had been advised by the ERCB it could extinguish the fire and have one more attempt to control the well prior to drilling a relief well. Amoco chose to cap the well while on fire, a procedure which had only been successfully completed six times, and on much smaller wells. Wild Well declined to attempt this procedure and, on 1 December, the well control firm of Boots and Coots Inc. was contracted to undertake capping the well while on fire. The procedure was to consist of cutting off a short section of the surface and intermediate casings to remove the old surface casing bowl along with a short top section of damaged surface casing, and then welding on a new bowl. The team would then strip on a spool and blind ram BOP, close in the flow, and pump mud down the hole until the well was controlled.

Cutting off the casing bowl commenced on 4 December and a new bowl was stripped over the intermediate casing stub and welded in place on 16 December. Several days of delay were then experienced due to equipment malfunction as well as unfavourable weather conditions. Finally, on 23 December 1982, the BOP stack was stripped over the intermediate casing stub and bolted to the casing bowl. Flare and kill lines were connected. Valves to the flare line were opened and the blind rams were closed. The flare valves were closed, the mud pumps were started, and weighted kill mud was pumped into the well. For all intents and purposes, the well had now been controlled.

Over the next 5 days, the operations of pumping mud into the well and bleeding off pressure were alternately applied until, after pumping in a total volume of 96 m^3 of mud, the well stabilized. This permitted entry into the wellbore and finally, on 28 December, utilizing a special riser and lubricator, a packer was set in the intermediate casing which secured the well and permitted a future change-out of the BOP assembly. The drama had ended.

In Appendix 6, the Panel has included a series of photographs of various events in the blowout incident. Not all of the photographs were submitted at the inquiry, but the Panel believes the reader may benefit from them being included in the report.

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Lodgepole Inquiry in Drayton Valley, Alberta.

Photo credit: G. Brosinsky, ERCB

4 ISSUES

Phase 1 of the inquiry extended over a period of 47 days, 245 exhibits were filed, and the transcripts of the evidence required over 9700 pages.

The evidence presented covered many aspects of the blowout and its effects, some of which were of a critical nature with respect to the impact of the event while others were of lesser importance.

After reviewing the evidence from the inquiry and the positions presented by the participants, and having in mind the terms of reference for the inquiry, the Panel considers the most important issues to be as follows:

(a) Cause of the Blowout and Adequacy of Actions Taken by Amoco to Prevent it,

(b) Well Control Activities and the Adequacy of Actions by Amoco and Others,

(c) Hazard to Human Health,

(d) Impact on the Environment and on Personal Property,

(e) Communication and Co-ordination,

(f) Adequacy of ERCB Responses Following the Blowout, and Its Regulations, Policy, and Procedure, and

(g) Adequacy of the Government Departments' Responses following the Blowout, and Their Regulations, Policy, and Procedure.

The Panel has addressed, in detail, what it considers to be the more critical of these areas and has dealt more generally with those of lesser impact. In all cases where it appeared to the Panel that recommendations for change were necessary, it has made such recommendations.

The seven issues listed above are discussed in sections 5 to 11. Section 12 summarizes the Panel's findings and recommendations, and section 13 attempts to analyse the significance those recommendations may have had on the 13-12 well, had they been in effect. Section 14 reports on progress to date respecting matters dealt with in the Phase 2 report.

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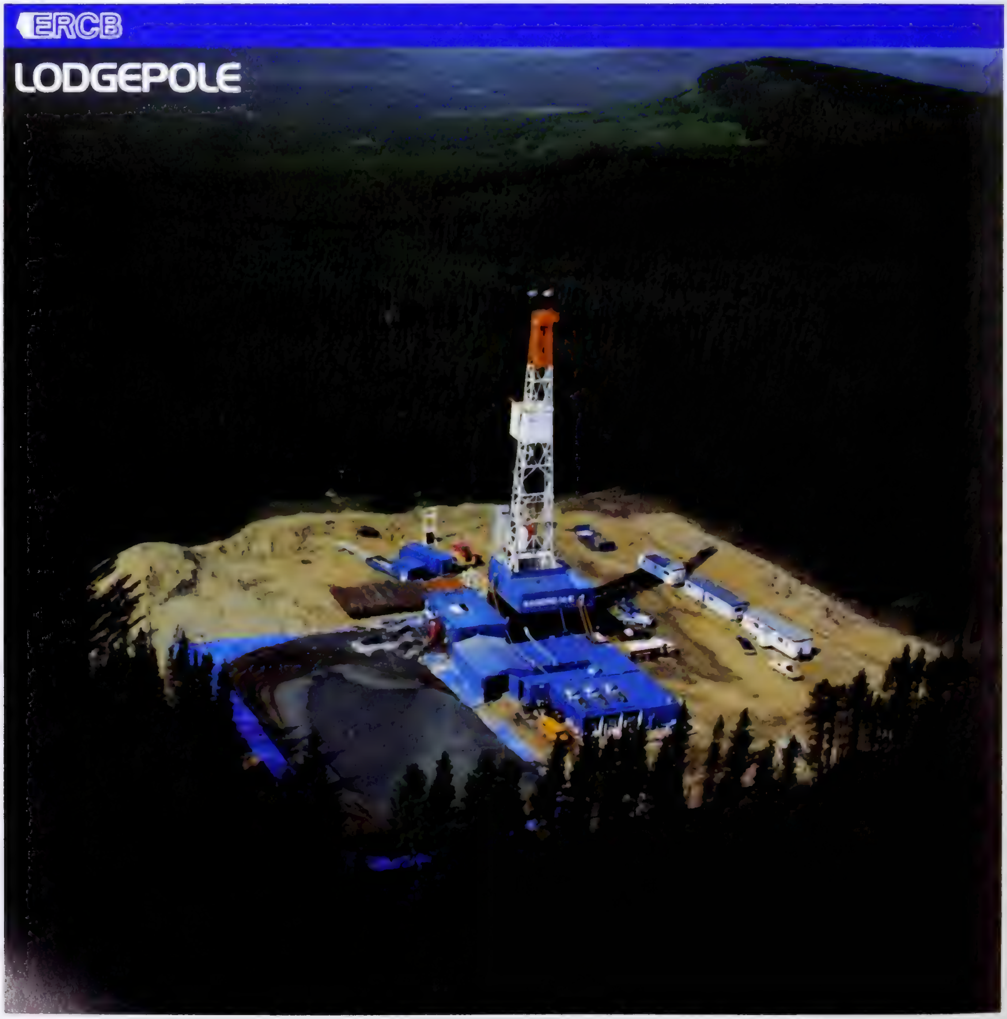
Nabors 14-E rig in the Alberta Foothills. (This is not the 13-12 location)



5 THE CAUSE OF THE BLOWOUT AND ADEQUACY OF ACTIONS TAKEN BY AMOCO TO PREVENT IT

5.1 Introduction

One of the Panel's primary objectives in the inquiry has been the identification and assessment of the factors contributing to the blowout of the 13-12 well. A correct understanding of those events is necessary to judge the appropriateness of the actions taken, and to plan changes in procedure or equipment which could reduce the possibility of future blowouts.

In this section, the Panel examines the factors which it believes contributed to the blowout, and whether Amoco took reasonable precautions with respect to each of the factors. In so doing, the Panel recognizes it is focusing attention on those facets where problems occurred, and that there were many other areas where actions by Amoco, its staff, and its contractors were proper and adequate. In making this assessment, the Panel has endeavoured to evaluate the suitability of the actions on the basis of information that was available to the well-site personnel at the time the actions were taken.

After reaching conclusions on Amoco's actions, the Panel at various places identifies drilling practices which, as a result of this particular experience, should be further investigated by the Blowout Prevention Review Committee (BPRC)[1] in order to overcome the noted deficiences.

The Panel has minimized specific references to Nabors and other suppliers of services and materials for the 13-12 well. These are regarded by the Panel as agents of Amoco and acting according to Amoco's direction and control.

5.2 A General Well Control Plan

A general well control plan, as referred to in this report, is a strategy which establishes the basic principles which must be followed to ensure that a well will not blow out during drilling, completion, or production operations. It rarely exists as a single document but, rather, is those portions of the drilling plan or program, special instruction bulletins (some posted in the doghouse), company procedure manuals, and other books, manuals, and written and verbal instructions that taken together aim to accomplish the objectives of a general well control plan.

In this section, the Panel focuses attention on the Amoco plan for the drilling of the 13-12 well.

Amoco indicated that it expected the 13-12 well to encounter sweet oil, but that the control plan definitely recognized and accounted for the possibility of sour gas. The Panel, as a result of reviewing the evidence, accepts that such was the case and does not believe the expectation for sweet oil played a direct role in the cause of the blowout. However, it may have influenced planning for the well and may have led to less caution in the drilling operations than might have been the case if the well was being drilled specifically for sour gas.

The drilling fluid (mud) system has a dominant position in the general well control plan for any well. The plan requires that the hydrostatic pressure in the wellbore be greater than the formation pressure. Hydrostatic pressure depends on the height of the column of drilling mud and the density of the mud. A reduction in either or both of these will reduce the pressure that results from the column or head of drilling mud. If the hydrostatic pressure is too low, a state of underbalance exists and fluids from the formation, such as gas, may flow into the wellbore. Unless this flow is properly controlled, a blowout will result. On the other hand, if the hydrostatic pressure is too great and a state of excessive overbalance exists, the drilling mud may flow into the formation. This is referred to as "lost circulation" and will result in a loss of hydrostatic pressure which can also lead to a blowout.

Operating practices can also influence the effective pressure exerted by the drilling mud column on a porous formation. The action of the mud pump working to circulate the mud down the drill pipe and up the annulus will add dynamic pressure to the mud column. When tripping drill pipe into the well, a temporary increase in pressure, or surge pressure, can be generated if the drill pipe is lowered too fast. A reverse condition, a reduction in pressure or swabbing effect, may occur if the drill-pipe assembly is hoisted too rapidly during tripping out operations.

In developing a drilling program, an operator must therefore consider formation pressures encountered at other wells in the general vicinity of the well being planned for and select a drilling mud density which will ensure a modest overbalance. To ensure that neither a state of underbalance nor of excessive overbalance develops as the well is drilled, close attention must be given to:

(a) mud density,

(b) any contamination of the drilling mud that will change its effective density, such as by drill cuttings (increase) or by air introduced during tripping (decrease),

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[1] The BPRC was established as a consequence of the decisions made by the Panel following Phase 2 of the inquiry. The committee is made up of representatives of industry and the ERCB, and has been asked to investigate a large number of blowout related questions. Recommendations are to be developed for consideration by the public and government, and for decision by the ERCB.

(c) maintaining a full mud column,

(d) the rate of lowering the drill pipe,

(e) the rate of hoisting the drill pipe, and

(f) pumping rate and pressure.

Should the hydrostatic pressure from the mud column prove to be insufficient, and as a consequence, formation fluids such as gas enter the wellbore, a kick condition would exist. Procedures have been developed such that those fluids may be controlled within the wellbore using the BOP system mounted on the well casing. The gas is flared at the surface and control operations are continued until the flow is progressively restricted and stopped. If the kick has occurred and efforts to control and contain the in-flowing formation fluids have failed, an uncontrolled flow or blowout results and re-establishing control may be both technically difficult and dangerous.

The general well control plan must include the procedures to be used to circulate out the kick, and it must also ensure that proper equipment will be available should a kick occur. This includes the BOP system but additionally, casing and drill pipe design and selection are important components of the plan.

In order to carry out the general well control plan, the detailed drilling plan must provide for the integrity of the drilling fluid system throughout the drilling operation regardless of the circumstances encountered. The operator should have on site at critical times experts in geology and mud properties. The operator must also ensure that the drilling and well equipment, particularly the BOP, is functioning properly. Finally, for the general well control plan to be implemented effectively, on-site supervisors and the drilling crew must be properly trained, regularly briefed, and always prepared to act promptly in carrying out prescribed kick control procedures.

5.3 Control Factors at the 13-12 Well

Amoco filed documents providing details of its drilling plan, drilling mud program, rig and well equipment, and qualifications of well-site crew and supervisors. It also provided a detailed chronology of events leading to the blowout, and provided panels of expert witnesses to address the events surrounding the blowout.

After careful scrutiny of the many details, the Panel has concluded that the following areas appear most important with respect to loss of control in drilling the 13-12 well:

(a) integrity of the drilling mud system,

(b) integrity of the drilling and blowout prevention equipment, and

(c) human factors relating to the event.

Figure 5.1 is a sketch showing the layout of the drilling, blowout prevention, and mud circulating system.

5.4 Integrity of the Drilling Mud System

The integrity of the drilling mud system at the 13-12 well during critical periods from 13 to 17 October was primarily a function of the mud density, drilling practices during coring, effects of H_2S on mud properties, and adequacy of active mud supply and the mud supply replacement system.

5.4.1 Density of the Drilling Mud

In developing its drilling plan, Amoco reviewed information concerning formation pressures encountered at a large number of other wells in nearby areas. These indicated that the pressures in the formation of interest at the 13-12 well would ordinarily be around 33 000 to 35 000 kPa. In isolated cases, pressures as low as 22 430 kPa and as high as 46 540 kPa had been reported. Amoco decided to design the drilling mud density to meet a pressure of 33 600 kPa with provision for increasing the density if higher pressure was encountered.

Amoco also indicated that its normal practice was to design mud density to provide a mud column overbalance of some 1500 kPa above the expected formation pressures. During drilling or coring operations, mud pump pressures would add further to this, resulting in an overbalance which should avoid the possibility of excess fluid head and lost circulation but at the same time prevent influx of reservoir fluid.

Calculations by the Panel indicate that, at the predicted Nisku reef depth of 3035 m, the planned mud density of 1150 kg/m^3 would result in an overbalance of some 630 kPa relative to the expected pressure of 33 600 kPa. Since hydrostatic pressure is directly proportional to the vertical height of the mud column, true vertical depth and not measured depth must be used in these calculations.

Additional pressure resulting from the mud pump would be in the order of 600 kPa, resulting in a planned overbalance of some 1230 kPa while circulating the mud. However, the pump pressure is not always present and when hoisting the drill pipe out of the hole, there is a swabbing effect that would further reduce the bottom-hole mud column pressure.

Actual mud density was 1165 kg/m^3 when the Nisku was penetrated at 3024 m true vertical depth(3051 m measured depth). This would have resulted in an overbalance of 950 kPa relative to an expected Nisku formation pressure of 33 600 kPa. The mud density was later increased to 1175 kg/m^3 prior to the start of core

No. 3. If the actual mud weight of 1175 kg/m^3 is considered when core No. 3 was broken off, an overbalance of 1246 kPa would result relative to the top of the Nisku formation and 1418 kPa at the bottom of core No. 3.

As indicated earlier in this section, it is necessary to use a mud density which is neither too low, thus allowing an influx from the formation, nor too high, which could result in lost circulation. This means there is a range of mud density within which operations must take place. The closer one is to the upper or lower limit, the more careful drilling procedures must be. If the mud density is within the range but towards the "high limit", care must be taken to avoid lost circulation. For example, the mud volume must be carefully monitored and the crew must be ready to add lost circulation material. If the mud is closer to the "low limit", drilling must proceed slowly, the potential for a kick must be carefully monitored, and plans to quickly weight up the mud must be in place.

The range of appropriate mud densities varies for each situation, and at the 13-12 well, because of the high reservoir pressure with very good permeability, it was likely relatively narrow. The planned pressure overbalance of 630 kPa, plus or minus the effects of operations such as pumping or pulling out of the hole, was less than the 1500 kPa normally used by Amoco. As noted previously, the effect of encountering the Nisku formation somewhat higher than predicted, at 3024 m rather than 3035 m, was to lower the "planned" overbalance even further. On the other hand, the actual mud weight of 1165 kg/m^3 for cores No. 1 and 2 and 1175 kg/m^3 for core No. 3 was greater than the planned weight of 1150 kg/m^3. Notwithstanding, there is an indication that the planned mud density was on the low side of the range, even though it was increased during drilling. The on-site supervisor should have been aware of this and thus should have planned to use particularly cautious procedures in coring into the Nisku formation.

The above assessment relates to theoretical calculations and planning for the proposed mud density. Actual experiences during operations at the well are of utmost importance and must also be considered when drawing conclusions respecting the adequacy of the mud density. With respect to these operations, no kicks were experienced when drilling into the reef on 13 October, nor during the cutting of cores No. 1 and 2. This suggests the mud density was above the lower limit of the "safe" range. Conversely, records indicate that considerable seepage losses, totalling over 18 m^3, occurred between drilling out of the intermediate casing at 13:00 on 13 October and recovering core No. 2 at 16:00 on 16 October. These losses could have been interpreted by on-site personnel as warnings of lost circulation and that the mud density was approaching its upper limit.

The apparent conflict between the Panel's calculation of required mud density to maintain well control and the reported seepage losses lead it to examine in more detail the validity of these losses. The Panel notes that the reported seepage losses occurred during four separate tripping-out operations, each over a relatively short 4.0- to 4.5-hour time period. The swabbing effect would tend to reduce the hydrostatic pressure, and therefore seepage at these times would be expected to be at a minimum. During other activities, such as tripping in and circulating, seepage would logically have continued at the same or increased rate. Extrapolation of the reported seepage losses to a 24-hour period implies daily losses of 20 to 35 m^3. Losses of this magnitude would be extremely serious and would require suspension of drilling operations and prompt corrective action.

After careful consideration, the Panel concludes that losses in the order of 20 to 35 m^3/day could not have occurred, as they were not reported in any of the evidence. Additionally, the records do not show that drilling operations were suspended or that the addition of drilling mud additives was required to correct a major lost circulation problem. Also, the records do not indicate that large volumes of mud were mixed to replace supplies that were reputedly lost by seepage. The Panel is satisfied that the reported seepage losses of 18 m^3 did not, in reality, occur at least to the extent reported. Instead, the "losses" were likely the result of some undetermined procedural or equipment calibration error.

In summary, the Panel concludes that the planned mud density for the 13-12 well was on the low side and therefore extra care should have been specified during the critical period of drilling into the Nisku zone. Although substantial seepage losses were reported and these might have been interpreted by on-site personnel as an indication that the mud was on the heavy side, an analysis of the situation indicates that the reported losses were likely due to errors. This is an indication that the drilling practices being used were less than satisfactory.

5.4.2 Drilling Practices During Coring Operations

Amoco testified that it had exhaustively reviewed the events preceding the blowout and had great difficulty in developing an explanation as to why the gas kick had started during the core No. 3 operations. Eventually, it concluded that the most plausible reason was that of a swabbing action caused when hoisting the drill string and shutting down the pumps to insert a 4-m pup joint immediately prior to the start of coring. It reasoned that this triggered a momentary underbalance during which gas could have flowed into the wellbore. Amoco indicated this was followed by several additional influxes.

The Panel has also made a careful analysis of all evidence relating to events prior to the blowout. Details of its analysis are presented in Tables 5.1, 5.2, 5.3, and 5.4, and Figures 5.2, 5.3, and 5.4.

Table 5.1 is a summary of the time required for the various procedures during the coring operations.

The most noteworthy time periods are those taken to circulate to bottom and clear trip air (column 3) and for circulation after coring (column 5). These were progressively reduced as operations proceeded from core No. 1 through to core No. 3. These reduced times suggest that drilling practices were becoming lax, and as

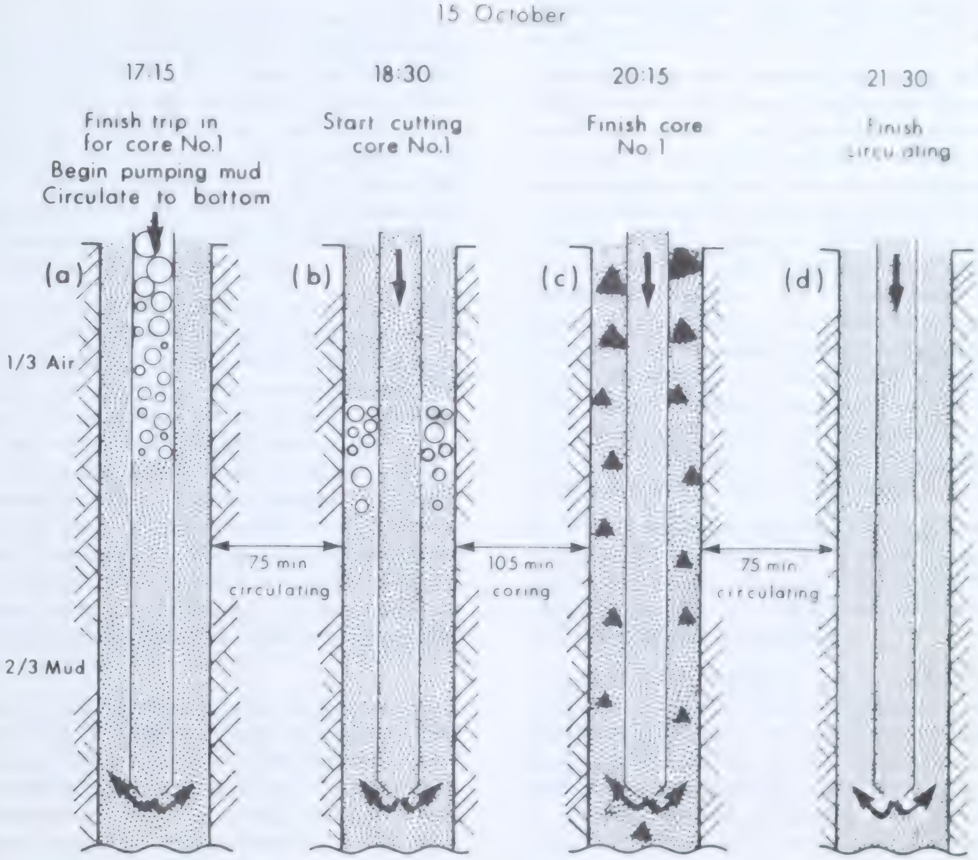
TABLE 5.1 SUMMARY OF TIME REQUIRED (MINUTES) DURING CORING OPERATIONS AT THE 13-12 WELL

1	2	3	4	5	6	7
Core No.	Trip In	Circulate to Bottom & Clear Trip Air	Coring	Circulation After Coring	Flow Check	Trip Out
1	195	75	105	75	15	255
2	240	60	75	30(a)	15	255
3	255(b)	20	55			

(a) 45 minutes, less 15 minutes for flow check.
(b) 330 minutes, less 75 minutes for servicing and crew change.

TABLE 5.2 DETAILED DRILLING PRACTICES WHILE OBTAINING CORE NO. 1 AT 13-12 WELL

Time/Date	Operation	Corresponding Pictorial	Remarks
14:00 15 Oct	Start trip in to cut core #1		- No indication of problems
17:15 15 Oct	Finish trip in for core #1	5.2(a)	- Some 2/3 of pipe filled through hole in float valve, upper 1/3 full of air
18:30 15 Oct	Start cutting core #1	5.2(b)	- After 75 minutes to fill hole and circulate to bottom, trip air displaced about 3/4 up the annulus
20:15 15 Oct	Finish core #1	5.2(c)	- 105 minutes of circulating while coring clears trip air, small amounts of core gas throughout annulus
21:30 15 Oct	Finish circulating	5.2(d)	- Circulating 75 minutes, which is bottoms-up time, clears annulus of core gas, flow check (15 minutes) shows no flow
03:00 16 Oct	Finish trip out & recovery of core #1		- No apparent problems



Note:

20 minutes required to compress trip air and circulate out of drill pipe

75 minutes required to circulate from bottom of hole to surface

Legend

▨ Drilling mud

▲▲ Gas released from coring operations

○o Air from tripping empty drill pipe into hole

FIGURE 5.2 LIKELY WELLBORE SITUATION. Core No.1

coring operations into the formation proceeded without apparent problems, less attention was given to the practices being followed.

Tables 5.2, 5.3, and 5.4, with the assistance of Figures 5.2, 5.3, and 5.4, analyse the coring procedures in detail. The first two columns of the tables show the various times and the particular operations taking place at those times for each of the three cores. The likely state of the wellbore at these particular times is illustrated in the series of pictorials identified in the third column. The remaining column in the tables briefly describes the logic and reasons why the Panel concludes the wellbore situations were as shown in the figures.

While tripping in (Figures 5.2(a), 5.3(a), and 5.4(a)), drilling mud would have entered the drill pipe through the 3.175-millimetre (mm) (1/8-inch) hole drilled in the flapper valve of the drill-pipe bottom-hole assembly. Based on the time required to trip in, it is estimated the drill pipe would fill to two-thirds of its internal volume. The amount of fill actually obtained could have been considerably less if the hole had been plugged, for example, by a piece of rock cutting from the coring operation. Under these circumstances, the amount of air trapped in the drill pipe would have been much larger. However, the time required to circulate the air down the drill pipe and up the annulus would have been approximately the same regardless of the amount of air.

Table 5.2 and Figure 5.2 relate to the first core. They suggest that the practices up to this stage resulted in no apparent problems. The times to circulate to bottom and for circulating after coring were both 75 minutes which is "bottoms-up time". The annulus would have been cleared of core gas prior to tripping out. The Panel believes it significant that the flow check taken prior to tripping out of the hole with core No. 1 was negative.

Table 5.3 and Figure 5.3 describe what occurred during the cutting and recovery of core No. 2. Procedures appeared to have become somewhat relaxed as compared to core No. 1. For example, the circulate to bottom cycle was discontinued much sooner than with core No. 1 (60 minutes rather than 75 minutes), and the circulation following the coring was for only 30 minutes and was not sufficient to clear the annulus of core gas. While there were no apparent serious problems, at 16:00 on 16 October, prior to commencing operations for core No. 3, the Panel expects that core gas remained in the annulus and could have set the stage for subsequent problems.

Table 5.4 and Figure 5.4 relate to core No. 3. They show that the annulus still contained core gas from core No. 2 and the time taken to circulate prior to coring was not sufficient to clear the annulus of that gas. The consequence would be to reduce the hydrostatic pressure, and coupled with the presence of trip air and the swabbing effect of lifting the drill pipe and core assembly off bottom to install a pup joint, likely resulted in the first influx of gas into the wellbore as shown in Figure 5.4(c).

The Panel believes that there was likely a second influx when core No. 3 was broken off and the pipe was picked up off bottom as shown in Figure 5.4(d). At this stage, air and gas in the annulus would have achieved maximum expansion which may have reduced the hydrostatic pressure of the mud column enough to allow a continuous formation gas influx during the period 22:50 to 23:30 on 16 October, when a flow check was being conducted and the additional pressure from the mud pump was not present. The probability of influxes No. 2 and 3 occurring is supported by a review of the events that followed, culminating at 02:30 on 17 October with a large flow of gas at surface and the first degasser failure. The durations and rates of circulation from 23:00 on 16 October to 02:30 on 17 October was approximately that required to result in an influx at 23:00 arriving at surface at 02:30.

The Panel's assessment respecting the likely timing at which gas influxes into the wellbore may have occurred is identical to Amoco's, except that Amoco made no mention of the possibility of an influx taking place while the flow check was being conducted.

The preceding review indicates that the problems at the well, which eventually resulted in the blowout, started during coring operations and resulted from inadequate hydrostatic pressure to keep gas from entering the wellbore. A heavier mud might have reduced the amount of influx that occurred, particularly when the coring assembly was lifted off bottom. The Panel concludes that the more serious aspects of the problem resulted from inadequate care taken during coring operations. This may have resulted because on-site supervisory personnel did not fully appreciate the potential of the formation into which they were drilling, and the density of the mud being used was such that it would provide only a modest overbalanced condition, and then only when the mud column in the wellbore was adequately maintained.

5.4.3 Effects of H_2S on Drilling Mud Properties

Amoco required that the mud pH be kept relatively high, 10.5 to 11.0, to reduce the possibility of hydrogen ion attack on the drill pipe in the event of H_2S exposure. As well, it required the use of iron oxide scavenger to neutralize any H_2S that might be encountered.

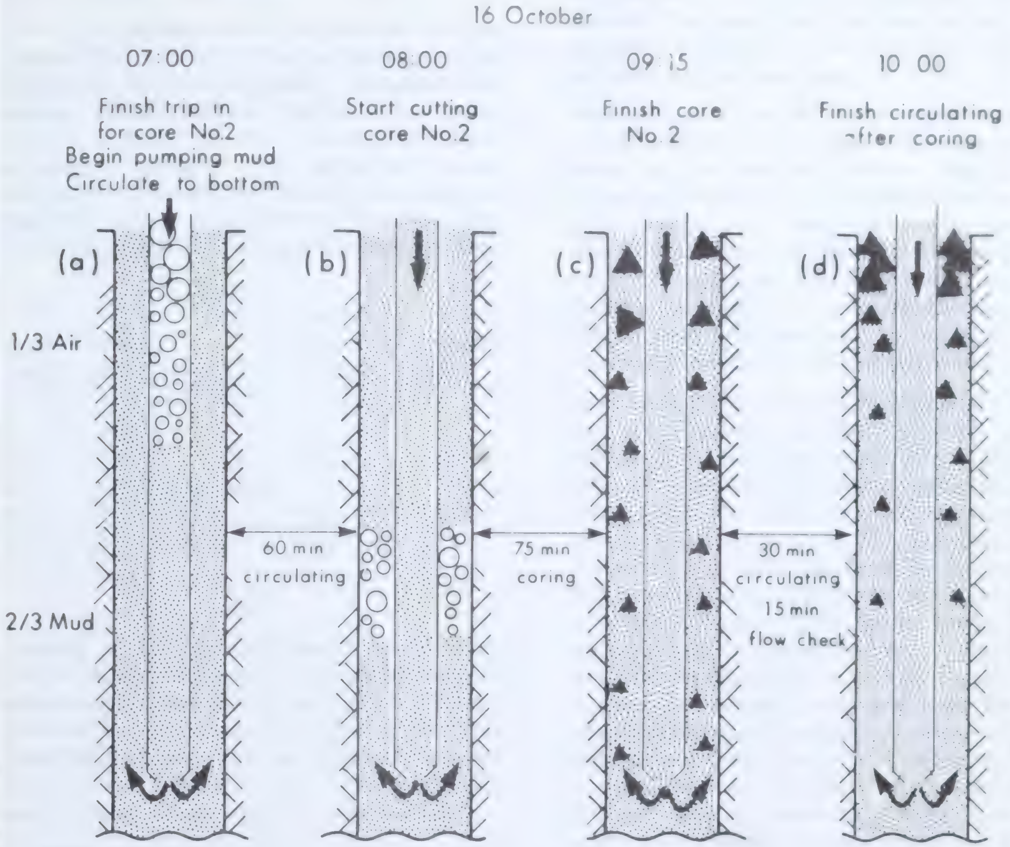
The Panel notes that there is some controversy in industry as to the effectiveness of iron oxide as an H_2S scavenger. The literature reviewed by the Panel indicates that iron oxide has a relatively low reaction rate at high pH. However, the Panel notes the evidence that for the 13-12 well, the H_2S contaminated mud looked black, sticky, and viscous, which tends to confirm that the iron oxide was reacting with the H_2S to form iron pyrite.

The Panel also questions whether a heavily H_2S contaminated mud could be readily reconditioned or be suitable for recirculation as it might not function as an effective drilling fluid.

The Panel concludes that the evidence with respect to the effect of H_2S on drilling mud is not clear. Similarly, the role this may have played in the cause of the blowout is not certain. The Panel notes that the BPRC will be reviewing the use of scavengers, as well as the effect on various mud properties of H_2S contamination.

TABLE 5.3 DETAILED DRILLING PRACTICES WHILE OBTAINING CORE NO. 2 AT 13-12 WELL

Time/Date	Operation	Corresponding Pictorial	Remarks
03:00 16 Oct	Start trip in to cut core #2		
07:00 16 Oct	Finish trip in for core #2	5.3(a)	- Some 2/3 of pipe filled through hole in float valve, upper 1/3 full of air
08:00 16 Oct	Start cutting core #2	5.3(b)	- After 60 minutes to fill hole and wash to bottom, trip air displaced about 1/2 way up the annulus, compared to 75 minutes and about 3/4 for core #1
09:15 16 Oct	Finish core #2	5.3(c)	- 75 minutes of circulating while coring clears trip air, small amounts of core gas throughout annulus
10:00 16 Oct	Finish circulating and flow check	5.3(d)	- Circulating 30 minutes is well short of bottoms-up time (75 minutes) so upper 3/5 of annulus contains core gas which has expanded due to reduced pressure, flow check (15 minutes) shows no flow
16:00 16 Oct	Finish trip out & recovery of core #2		- No apparent problems but some core gas remains in annulus even though gas was rising when mud was not being circulated



Note:

20 minutes required to compress trip air and circulate out of drill pipe.

75 minutes required to circulate from bottom of hole to surface.

Legend:

▨ Drilling mud

▲▲ Gas released from coring operations

○○ Air from tripping empty drill pipe into hole

FIGURE 5.3 LIKELY WELLBORE SITUATION. Core No. 2

5.4.4 Adequacy of Mud Supply and the Replacement System

Amoco indicated that one of its reasons for selecting the Nabors 14E rig for the 13-12 well was that it had modern drilling mud facilities and relatively large capacity mud tankage. Amoco's schematic of the drilling mud system is shown in Figure 5.5. There were 6 main tanks of which tanks 1 through 5 constituted the active system and tank 6 was set aside for holding prehydrated bentonite that could be committed to mud make-up supply as and when required. The capacities of the tanks were:

Main Tanks	Capacity (m^3)	Small Inset Tanks	Capacity (m^3)
1	25.7		
2	28.1		
3	21.5	Mixing	1.2
4	34.0 (suction tank)		
5	31.3 (suction tank)	Pill	5.3
6	23.5 (premix)	Trip tank	6.8
	164.1		13.3

Counting all tanks, the total capacity was 177.4 m^3. After subtracting the premix, mixing, and pill tanks, the net active system tankage at full capacity was 147.4 m^3. However, the bottom approximately 0.45 m of the tanks were effectively dead storage and could not be accessed by the pumps, resulting in some 23 m^3 of unusable storage capacity in the combined active tankage.

In assessing the role which the availability of mud played in the cause of the blowout, the Panel has attempted to reconstruct the mud supply situation commencing with drilling out of the intermediate casing. Unfortunately, the record is not completely clear. The estimated mud supply as pieced together from the evidence is presented in Figure 5.6.

Amoco's mud company service reports fix the volume in the mud tanks as 80 m^3 on 13 October, increasing to 100 m^3 on 16 October. This agrees with evidence at the inquiry that 100 m^3 of mud was available at the time core No. 3 was cut during the late hours of 16 October. Additionally, the evidence indicated that mud was being lost by seepage between 13 and 16 October, but as discussed in section 5.4.1, the Panel doubts that these losses indeed occurred, at least to the extent reported.

Figure 5.6 shows that the mud in tanks 1 to 5, when the first problems were noticed and core No. 3 was broken off, was 100 m^3, of which some 23 m^3 could not be readily pumped. Additionally, there would have been some 109 m^3 of mud in the wellbore and about 20 m^3 of readily accessible prehydrated mud in tank 6. A high-speed mixer and mud ingredients were also available. The situation in the wellbore was very likely that shown in Figure 5.4(d) where the second significant gas influx had just taken place.

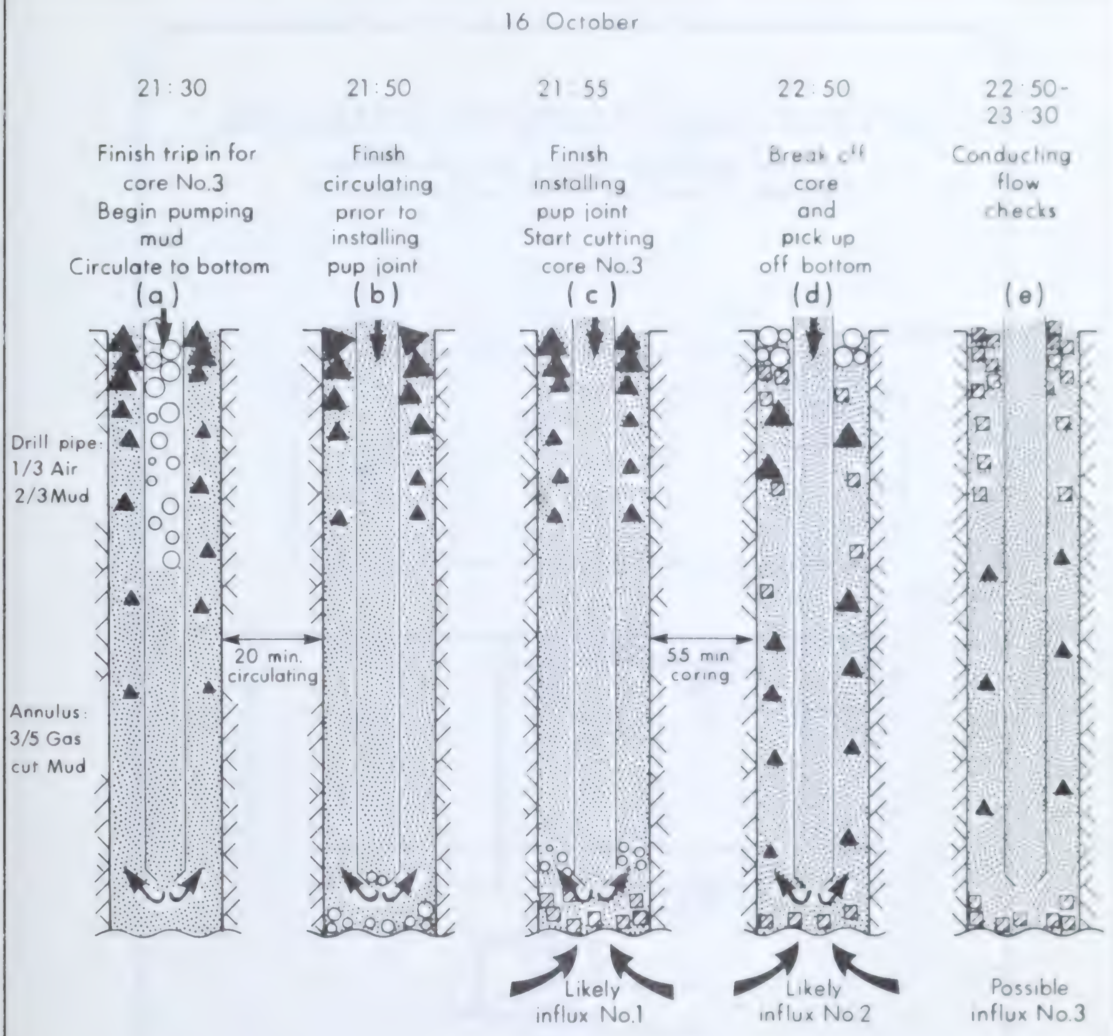
After breaking off core No. 3, flow checks were conducted and the well was circulated. There is no indication of any new mud being mixed or losses in mud volume until the degasser failed for the first time at about 02:30 on 17 October. It was estimated, at that time, that some 10 m^3 of mud had been blown onto the ground and the tanks had gained some 10 m^3 from the wellbore. The tank gain is shown in Figure 5.6. The 20-m^3 loss from the wellbore had presumably been replaced by gas, significantly reducing the hydrostatic pressure.

Amoco estimated that when the degasser failed a second time, 30 m^3 of mud was blown onto the ground. Different items of evidence suggest that, at this time, about 05:00 on 17 October, some one-half of the initial mud was available, and that the active tanks were about one-third full. This would mean there were some 50 m^3 of mud left in the tanks. The Panel has not been able to fully reconcile this estimate with the 100-m^3 supply at the time of the first degasser failure. The circulation which had been interrupted by the first degasser failure would have replaced some of the mud voidage in the wellbore, thus reducing the mud in the tanks. The combination of the circulation and the second degasser failure reduced the mud supply to the 50 m^3 shown on Figure 5.6. At about 04:30, a portion of the prehydrated mud had been mixed with about 15 m^3 of the active mud supply, and the mixture was being weighted up with the high-speed mixer. Whether or not this was part of the 50-m^3 supply is not clear from the evidence.

What then took place in terms of mud supply is equally uncertain. Apparently, mud was being mixed, weighted up, or reconditioned while the degasser was being repaired, and again this might have involved the prehydrated mud. After 08:30 when the degasser repairs were finished, mud was being weighted up and reconditioned for 2.5 hours because it was decided that insufficient mud was available to commence circulation. It is also known that after the drill pipe failed at 06:45, pressure was being bled off through the manifold and some mud would have blown out onto the ground. In any case, the record indicates that after circulating an estimated volume of 15 m^3 from 11:00 to 13:00 at the reduced pump speed, the suction tank volume was used up and circulation again had to cease. Whether this referred to all of the mud available, as is assumed in Figure 5.6, or whether it referred only to the mud that had been adequately reconditioned and weighted up is not clear.

TABLE 5.4 DETAILED DRILLING PRACTICES WHILE OBTAINING CORE NO. 3 AT 13-12 WELL

Time/Date	Operation	Corresponding Pictorial	Remarks
16:00 16 Oct	Start trip in to cut core #3		
21:30 16 Oct	Finish trip in for core #3	5.4(a)	- Upper 1/3 of pipe full of air from trip, annulus still contains core gas due to insufficient circulation after core #2
21:50 16 Oct	Finish circulating, prior to installing pup joint	5.4(b)	- Circulated 20 minutes to fill drill pipe and wash to bottom, annulus may still contain core gas and trip air is compressed at bottom of hole
21:55 16 Oct	Finish installing pup joint, start cutting core #3	5.4(c)	- Annulus may contain core gas at top, contains trip air near bottom, and the swabbing effect of lifting pipe to install pup joint reduces the hydrostatic pressure of fluid column, likely resulting in influx of gas at bottom
22:50 16 Oct	Mud splashing from flow nipple, break off core & pick up off bottom	5.4(d)	- 55 minutes circulating while coring moves trip air and gas influx #1 to top of annulus. The splashing, bubbling, and high gas detector readings observed confirms that the gas influx had reached surface after only 55 minutes of circulating. The circulated bottoms-up time is 75 minutes. This, more rapid than expected movement, is probably due to the buoyancy of the gas influx accelerating the displacement mechanism. While moving up, air & gas expand thus reducing hydrostatic head. Swabbing action coupled with reduced hydrostatic pressure likely results in further influx.
22:50- 23:30 16 Oct	Conducting flow checks	5.4(e)	- Possible additional gas influx takes place when coring stopped and pump pressure eliminated from hydrostatic, may have continued for next 40 minutes while conducting flow checks.



16 October
21:30
Finish trip in for core No.3 Begin pumping mud Circulate to bottom
(a)
21:50
Finish circulating prior to installing pup joint
(b)
21:55
Finish installing pup joint Start cutting core No.3
(c)
22:50
Break off core and pick up off bottom
(d)
22:50-23:30
Conducting flow checks
(e)
Drill pipe: 1/3 Air 2/3 Mud
Annulus: 3/5 Gas cut Mud
20 min. circulating
55 min coring
Likely influx No.1
Likely influx No.2
Possible influx No.3

Note:

20 minutes required to compress trip air and circulate out of drill pipe.

70 minutes required to circulate from bottom of hole to surface

Legend

░ Drilling mud

▲▲ Gas released from coring operations

○○ Air from tripping empty drill pipe into hole

▨▨ Gas influx from formation

FIGURE 5.4 LIKELY WELLBORE SITUATION. Core No.3

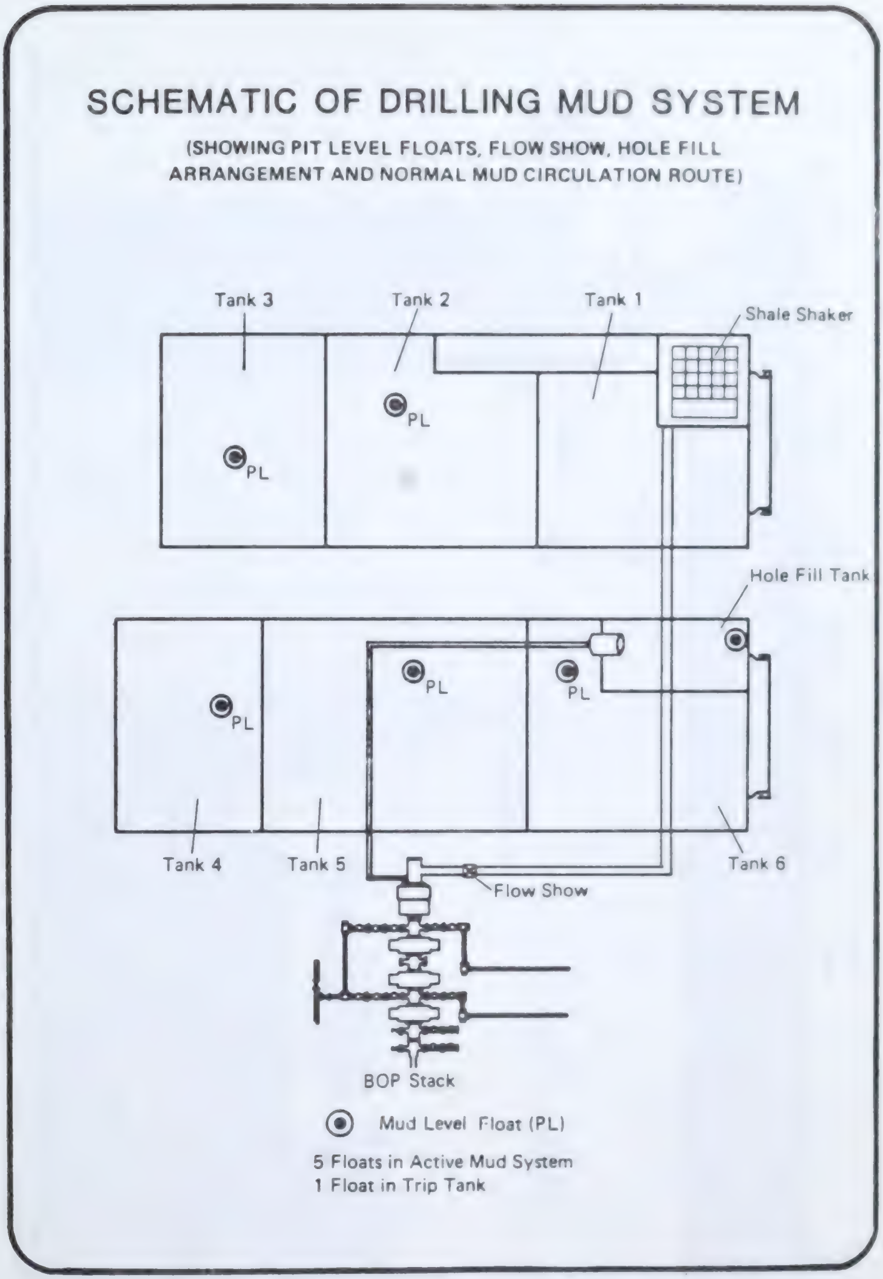

SCHEMATIC OF DRILLING MUD SYSTEM
(SHOWING PIT LEVEL FLOATS, FLOW SHOW, HOLE FILL ARRANGEMENT AND NORMAL MUD CIRCULATION ROUTE)
Tank 3
Tank 2
Tank 1
Shale Shaker
PL
PL
Hole Fill Tank
PL
PL
PL
Tank 4
Tank 5
Tank 6
Flow Show
BOP Stack
Mud Level Float (PL)
5 Floats in Active Mud System
1 Float in Trip Tank

FIGURE 5.5 AMOCO'S SCHEMATIC OF DRILLING MUD SYSTEM.
Reproduced from Exhibit No. 66.1.

[illegible]

[illegible]

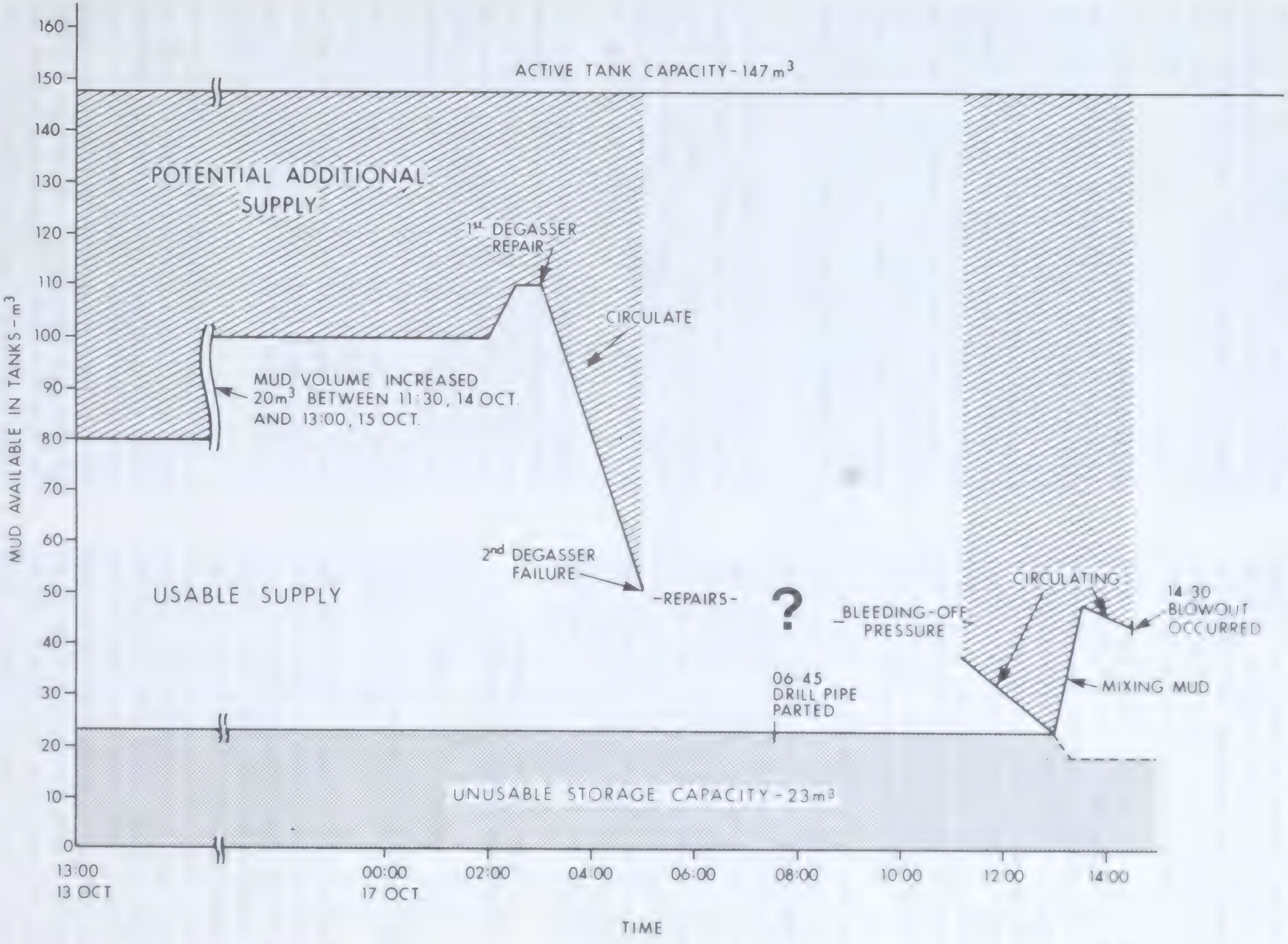


FIGURE 5.6 ESTIMATED MUD SUPPLY AT SURFACE OF THE 13-12 WELL. **Assuming no seepage** losses.

? - Period of uncertainty respecting mud supply. The evidence indicates that some new mud mixing, reconditioning, and weighting up took place in the period 05:00 to 11:00 but volumes and other details are not clear.

An additional 25 m^3 of mud was then obtained by mixing some new mud, and by combining the "unusable storage capacity" (Figure 5.6) into one tank. Circulation was recommenced at about 13:30, but only intermittent returns were obtained, suggesting that the hole contained large volumes of gas. The well blew out of control at 14:30.

The preceding review clearly indicates that insufficient mud was available during the kick-control operations. To illustrate, circulation could not recommence at 08:30 on 17 October when the degasser repairs had been finalized, but had to wait for mud to be weighted up or reconditioned. Amoco also ran out of mud at 13:00 and again had to cease circulation. Also, if there had been sufficient mud available, it may have been possible to continue pumping with the mud being circulated to the flare pit when the degasser failed the first time. Although such action would not normally be expected, it would have allowed kick-control procedures to continue uninterrupted and may have improved the situation.

It is not certain as to whether the kick would have been controlled if additional mud had been available, but the Panel believes there is a good chance that it may have been. Inadequacies in mud supply and the mud replacement system were thus a significant factor in terms of the cause of the blowout.

The remaining question relates to the reasons for these inadequacies. It is clear that no more than approximately 80 m^3 of accessible mud was in the tanks, other than the prehydrated mud, after the intermediate casing was drilled out. That supply was less than the volume of mud in the hole (109 m^3) and represented only about two-thirds of the capacity of the mud tanks. This may be in accordance with common industry practice, but subsequent events demonstrated it was inadequate for drilling into a potentially sour zone. This suggests that a more cautious approach of ensuring that a greater supply of mud is available would be appropriate when drilling in critical sour zones.

Amoco had chosen to use a high-speed mixer along with the 20 m^3 of prehydrated mud, rather than a much larger standby volume of ready mixed mud. The reasons given for this was that greater flexibility was provided because the mud in the active system could be conditioned or weighted up in a very short time with the high-speed mixer to whatever conditions were required, whereas the standby mud would have been designed ahead of time and may well have been at the wrong density, thus requiring further processing. The evidence did not suggest that the availability of mud was affected by the mixer itself. However, given insufficient supplies of mixed mud on at least two occasions, the Panel must conclude, with the benefit of hindsight, that a premixed supply of mud would have assisted in efforts to control the kick. From this experience, the Panel concludes that there must be an appropriate back-up mud system for critical sour wells. It believes the BPRC should consider this matter and make recommendations.

It also appears that manpower was not available at the 13-12 well to mix mud when repairs were being made to the degasser and other equipment. Since additional crew members were available at the nearby camp and were not called out to assist, this suggests that the on-site supervisor did not treat the situation as seriously as he might have. This may have resulted from inadequate planning by way of emphasizing to the on-site personnel that sour gas was a possibility and that the avoidance of a blowout was particularly critical.

Consideration of this aspect of the event also raises the question of whether a sufficient number of masks and spare air cylinders would have been available had they been needed and additional crew members been called out. The Panel believes that, for critical sour wells, consideration should be given to changing the regulations to ensure that masks and air cylinders are also available for extra people that may be called onto a well site to deal with an emergency, and that such people are trained in the use of the masks. The matter of air masks and their usage is dealt with in greater detail in section 6.

5.5 Integrity of the Drilling and Blowout Prevention Equipment

5.5.1 Failure of the Degasser

Figure 5.7 is a cross-section of the type of degasser used at the 13-12 well.

During the initial attempts to circulate out the kick, from 23:30 on 16 October to 02:30 on 17 October, weighted mud was being gradually pumped into the well as an essential part of the kick-control procedure. When the degasser failed at 02:30, spilling an estimated 10 m^3 of mud out onto the ground, kick-control circulation was stopped for 30 minutes to permit repairs. The well was shut in during these repairs, therefore, any influx into the well would cease after a short period of build-up to stabilized pressure conditions within the wellbore. During an earlier shut-in period, from 01:00 to 01:45, the pressure build-up occurred in about 30 minutes. The Panel, therefore, concludes that the first degasser failure and the short 30-minute cessation of kick-control procedures probably allowed some influx but was not likely a significant contributor to the cause of the blowout.

Following repairs to the degasser, circulation was resumed for only 2 hours from 03:00 to 05:00, initially with no mud returns, when the degasser failed a second time as a slug of H_2S-exposed, gasified mud drove the float into the mud-outlet position. In this instance, repairs required some 3.5 hours, and with additional time for other repairs and mud mixing, circulation ceased for 6 hours.

As with the first degasser failure, the second should not in itself have been a major cause for concern, provided the well was shut in and pressure allowed to build up to prevent further influxes and the drill pipe was adequately protected. Initially, the well was shut in. However, after 1.75 hours, the drill pipe failed and the well was bled off to prevent the pressure from building up and forcing the drill pipe out of the hole. Undoubtedly, this led to very large influxes, and more seriously, loss of additional mud from the wellbore.

The Panel concludes that the failures of the degasser should not by themselves be regarded a primary cause of the blowout. However, the failures interrupted kick-control procedures and resulted in the drill pipe being exposed to H_2S without the protection provided by the circulating drilling mud. Eventually, the drill pipe failed and this was critical in terms of the cause of the blowout. In that sense, the degasser failures contributed in a major way to the blowout. This analysis confirms the need to have all components of a drilling system operating effectively.

Evidence at the inquiry indicated that the type of degasser installed on the Nabors 14E rig was not unusual for a closed mud system, and was in use on several other rigs in the province. Prior to the 13-12 incident, that type of degasser had apparently operated effectively but, as the Nabors crew testified, its efficiency had not been tested until an actual gas kick developed. While the Panel is satisfied that Amoco applied reasonable judgement in approving the Nabors degasser (Figure 5.7), it notes that Amoco, as a result of the 13-12 experience, recommended changes to the degassers.

The Panel agrees that degasser design should be evaluated, particularly for use on sour wells, and the design should be proven before use in the field. The Panel has specifically included a review of degasser design in the Terms of Reference for the BPRC. Until the committee has reported, and a more permanent policy is established, the Panel believes that drilling rigs on critical sour wells should either be equipped with a spare degasser in parallel, or some other equally effective system and related procedures, to be used in the event of a degasser failure.

5.5.2 Failure of the Drill Pipe

At 06:45 on 17 October, while the degasser was being repaired for the second time, the drill pipe parted, most likely due to hydrogen embrittlement caused by exposure to H_2S.

In preparing to drill the well, Amoco had the option of using either Grade E or Grade G drill pipe. The latter is more prone to failure due to hydrogen embrittlement, but provides greater strength if it can be protected from the effects of any H_2S that may be encountered. The increased strength was important in the case of the 13-12 well because of the projected depth, and also because of it being a directionally drilled hole. Amoco chose to use a combination of the E and G grade drill pipe, and to protect it by maintaining the pH of the mud at a relatively high level while adding iron oxide to the drilling mud to neutralize any H_2S contamination. The Panel accepts the logic of the Amoco position and does not see this as a deficiency in planning on the part of Amoco, even though hindsight reveals that a larger diameter, thicker wall Grade E drill pipe would have been a better choice.

Drill pipe design and the use of H_2S scavengers are both matters that have been referred to the BPRC. As well, the BPRC should look at other measures to protect drill pipe, including the internal coating of the pipe with plastic, or externally coating it with film forming inhibitors.

A related matter at the 13-12 well is that once the drill pipe parted, the upper portion was eventually forced out of the hole by the pressure. Amoco indicated that it had considered tying down the pipe with chains but had discarded this option because of the need to go under the rig floor to anchor it and the possibility that in doing so the pipe might be disturbed and begin to hydraulic again. Special snubbing equipment was ordered from Red Deer, but too late for it to arrive in time to be of assistance. The Panel believes the BPRC should look at more effective ways of anchoring the drill pipe in such situations.

5.5.3 Failure of the Casing Pressure Instruments

The diaphragm in one of the two casing pressure sensors had ruptured, allowing drilling mud to enter and plug off the hydraulic line to the pressure gauge in the manifold house. The second pressure sensor was connected by hydraulic line to a pressure gauge located on the rig floor, and the hydraulic line was found to be frozen off. As a result, neither pressure gauge was functioning properly.

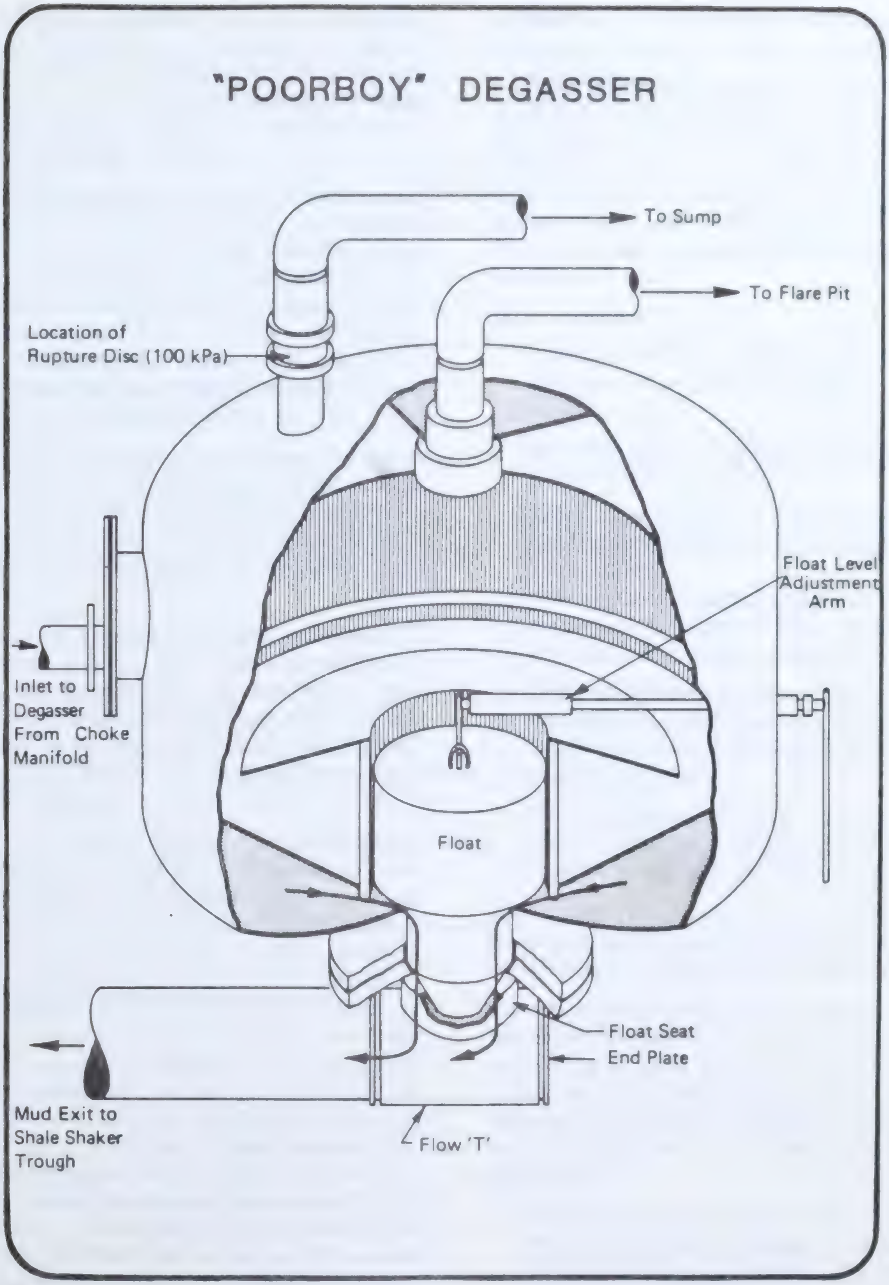

"POORBOY" DEGASSER
To Sump
To Flare Pit
Location of Rupture Disc (100 kPa)
Float Level Adjustment Arm
Inlet to Degasser From Choke Manifold
Float
Float Seat
End Plate
Mud Exit to Shale Shaker Trough
Flow 'T'

FIGURE 5.7 AMOCO'S DIAGRAM OF THE "POORBOY" DEGASSER. Reproduced from Exhibit No. 66.

The combination of the inside of the drill pipe and the annulus of a drilling well can be compared to the two legs of a U-tube. Under stabilized conditions, the sum of the pressures in each leg of the U-tube must be equal, whether the pressures are static or result from one or more partial columns of fluid.

Because the drilling fluid is circulated down the inside of the drill pipe and up the annulus, formation fluids entering the bottom of the well during a kick do not usually enter the drill pipe, but instead are circulated up the annulus. As a result, the sum of hydrostatic pressure of the column of mud in the drill pipe, which usually does not contain entrained formation gas, plus shut-in drill-pipe pressure at surface (SIDPP), is a direct measure of the pressure at formation depth in the well.

Because of the U-tube effect, a comparison of the shut-in casing pressure at surface (SICP) to the SIDPP will provide important information as to the fluid content of the annulus. In a kick situation, it is usual to have the SICP greater than the SIDPP, indicating the presence of gas in the annulus.

When influx No. 1 appeared to reach the surface at 22:50 on 16 October (Figure 5.4(d)), some mud was noticed bubbling and spashing from the flow nipple. Mud circulation was stopped and a flow check was conducted. Additionally, an H_2S odour was noticed on the rig floor. With the annular BOP then shut in, the SIDPP and SICP were reading zero.

At about 23:30, Amoco proceeded to circulate at reduced pump speed through the manifold and degasser with the annular preventer closed. Circulation continued until 00:45 on 17 October when circulation was stopped and the annular preventer was opened. A flow check was conducted and no flow was observed. Conventional circulation, with the annular preventer open, ie, direct to the tanks, was continued until 01:00 when a flow check indicated that the well was flowing. At this point, Amoco shut in the annular preventer and again determined the SICP which was zero and the SIDPP which was 2000 kPa. Even though the evidence suggests that Amoco did not become aware of the possible failure of the casing pressure instruments until approximately 01:45 on 17 October, it, at this point, appeared to assume that a kick had been taken and carried out kick-control calculations and commenced prescribed kick-control procedures.

The Panel believes that as a result of the failure of the casing pressure instruments, Amoco lacked information important to determine conditions in the wellbore when the first influx reached surface and may have failed to realize it had a serious kick on its hands. This likely explains why Amoco did not initiate kick response procedures at 23:30 but instead continued with various observations and other actions for almost 2 hours.

Amoco provided, with its documentary evidence, a copy of the kick circulation procedure posted on the wall of the doghouse at the Nabors 14E rig. According to the evidence, the drilling crew was required to follow the methods set out in that procedure. The highlights of the prescribed well control procedures are set out below, but the additional information in parentheses have been added by the Panel.

Kick Circulation:

1 Determine stabilized SIDPP and SICP.
(Both the drill pipe and annulus most be closed during this step.)

2 Start mud pump at reduced circulating rate.
(The drill pipe is opened.)

3 Adjust manifold choke to allow casing pressure to build up to SICP plus a suggested margin of 1400 kPa maximum.
(The annulus remains shut-in until the desired casing pressure is reached, at which point attention is directed to the drill-pipe pressure.)

4 Read drill-pipe pressure and maintain it constant by manifold choke adjustment, at a pressure equal to SIDPP plus reduced-speed pump pressure plus a nominal overbalance.

5 While circulating the kick, maintain constant, reduced, pump speed and hold drill pipe pressure constant by manifold choke adjustment.

After the kick has been circulated out, the well is killed in a second phase by increasing mud density and circulating the weighted mud in a prescribed manner.

The actions taken at the 13-12 well did not, during the first couple of hours, conform to Amoco's procedural requirements probably because it did not recognize that a kick had been taken. Two significant differences between the actions taken and those that probably would have been taken had the kick been recognized were as follows:

1 Circulation pressure from 23:30 on 16 October to 00:45 on 17 October would have been higher than the 2000 kPa used. It should have included an appropriate overpressure allowance of perhaps 1800 kPa as was used starting at 01:45 on 17 October. In order to introduce any overpressure at constant reduced pump speed, Amoco likely would have partially closed off the manifold choke. This would have resulted in an overpressure in both the casing and drill pipe, and would have ensured that no further influx took place at formation depth.

2 Circulation through the BOP manifold and degasser with the annular preventer closed would not have been interrupted at 00:45 on 17 October. Amoco's objective at this point should instead have been to continue circulating until it was certain any influx had been displaced out of the wellbore. This would have required a minimum of 150 minutes at reduced pump speed and would have ensured complete displacement of any gas that may have been in the annulus.

Throughout the situation previously described, a determination of casing pressure was desirable for the following specific reasons:

1 The difference in SIDPP and SICP is a direct measure of the difference in the hydrostatic pressure of the fluid in the drill pipe and casing, and therefore by difference, an indication of the magnitude of the influx that has taken place. An appropriate course of action is dependent on knowing both pressures.

2 In initiating standard kick-response procedures, the well remains shut-in as mud is pumped into the drill pipe until the casing pressure builds up to the pre-established SICP plus an appropriate margin to ensure pressure overbalance at formation depth to prevent further influx of formation fluids. Thereafter, the drill-pipe pressure primarily, but also the casing pressure, is monitored as kick-response procedures are continued.

It is possible that the course of action that Amoco followed in the absence of the casing pressure readings may have succeeded if other events had not intervened. The readings were certainly important, however, and the absence of them probably contributed to some of the uncertainties and delayed actions which appeared to exist during the initial responses to the first kick.

The preceding analysis illustrates the importance of the casing pressure instruments and the effect their failure may have had on the blowout. It also illustrates the potential consequence of any lack of rig equipment maintenance, which was the case with respect to the casing pressure sensor and gauges at the 13-12 well.

The Panel believes that improved training should stress to drilling personnel the importance of casing pressure, and the need for proper maintenance of instruments. Training and casing pressure sensors are both matters that have been referred to the BPRC.

5.5.4 The BOPs

Various components of the BOP stack were used extensively starting on 16 October when the kick was first experienced. Until the blowout occurred at approximately 14:30 on 17 October, the units all performed as required. Amoco's diagram of the BOP assembly is shown in Figure 5.8.

After the blowout occurred, there were concerns respecting exposure of the BOP stack and its electrical controls to the corrosive effects of H_2S. Similarly, the drill pipe that shot out of the hole on 1 November, and the fire that resulted, both damaged the BOPs. The post-event materials studies showed that the BOPs lived up to H_2S resistant ratings where those were specified.

Some of the participants at the inquiry questioned why shear rams were not installed in the BOP stack. While shear rams have been used in special circumstances, such as offshore drilling, they have not been used extensively in Alberta, and evidence at Phase 2 of the inquiry indicated both advantages and disadvantages to their use.

The Panel has asked the BPRC to look into many aspects of BOP equipment, including the use of shear rams, the need for H_2S resistant external BOP components, and the need to move the BOP master controls away from the well to reduce the possibility of direct exposure to H_2S.

5.5.5 Failure of the Travelling Block Hook Latch and Kelly Hose

The situation at the 13-12 well moved from a controlled kick to blowout status as the latch and kelly hose both failed in quick succession at 14:30 on 17 October. The block hook and latch assembly had been checked by the manufacturer's representative only a few days previously and was deemed suitable for service. It is interesting that the hook latch also failed at the SHELL ET AL UNIACKE G-72 well, but in that case, the kelly fell against the derrick and no strain was placed on the kelly hose to cause it to fail.

The Panel believes that there is a need to investigate improved designs and/or maintenance procedures for the hook latch. Similarly, there is a need to develop stronger kelly hose, trace the kelly hose with a chain or other material to absorb tensile stresses, or require a safety chain across the V-door of the drilling rigs. The BPRC should investigate these matters.

5.6 The Human Factor

Evidence presented at Phase 2 of the inquiry emphasized that human error was believed to be the most important factor in blowouts. Based on that belief, many witnesses contended that emphasis should be placed on training and careful selection of personnel. Particular emphasis was placed on the need for experience and knowledge in being able to satisfactorily deal with kick situations.

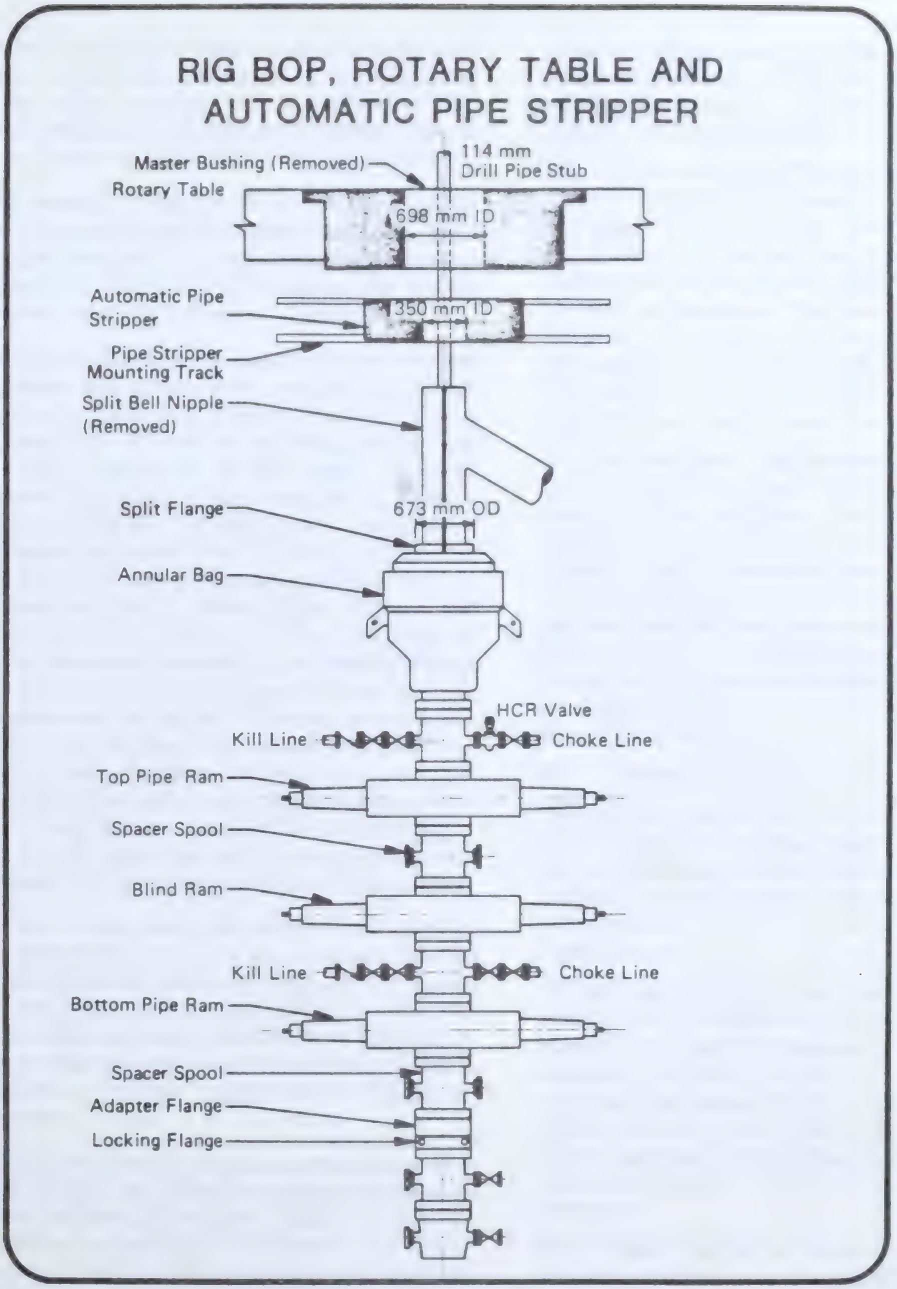


FIGURE 5.8 AMOCO'S DIAGRAM OF THE BOP, ROTARY TABLE AND AUTOMATIC PIPE STRIPPER.
Reproduced from Exhibit No. 66.

For the 13-12 well, the human factor was an important element in the selection of the drilling rig, the adoption of the drilling program, and the execution of that program in actual drilling operations. Decisions made in each of these areas had an influence on the final outcome.

With respect to drilling operations, the evidence shows that a kick occurred on 16 October around 22:50. Kicks do occur in the drilling of wells but are expected to be successfully circulated out of the system. This was not achieved and the well blew out of control.

Evidence presented at the inquiry indicates that the supervisors and drilling crew were well trained and experienced. There were, however, as indicated earlier, apparent errors or omissions in drilling practices and kick-control procedures. In this regard, the Panel believes it significant that the Amoco drilling foreman had been awake and working for more than 24 hours and the Nabors supervisor for 30 hours by the time the well blew out. Amoco gave evidence that it had staff and expertise available in Drayton Valley, Calgary, and indeed other parts of the world to assist personnel on site, yet, the on-site supervisors did not obtain additional help until problems had progressed for some time and were becoming very serious. While their actions in this regard may not have been unusual in the drilling industry, the Panel believes that under emergency conditions there is a need to ensure that the optimum decision is made. That can be achieved by having the people with the best knowledge and experience address the problems in a timely manner before they become critical.

The Panel is also concerned about the overall planning that preceded the actual events. It accepts that the normal or standard planning for contingencies probably took place. However, as events unfolded it turned out to be insufficient. Planning should address the matter of actions which would be taken in the event of various scenarios of unlikely occurrences or worst-case conditions.

The 13-12 well became a serious blowout because of a series of kicks and failure in the application of prescribed kick-control procedures during the night of 16 October and morning of 17 October. As indicated previously, the Panel is of the view that the kicks occurred primarily because Amoco did not employ sufficiently cautious practices during drilling. The kick-control procedures did not commence soon enough, or if they did, they were not totally consistent with prescribed procedures and were interrupted at a time when they should not have been, either because of human error or equipment failure. This raises the questions of whether existing control procedures are adequate for critical sour wells, whether training in these areas is adequate, and whether special expertise is needed on site for certain critical wells. The Panel also recognizes that existing procedures do not provide for the unexpected, such as the failure of equipment.

The Panel believes the BPRC should consider these matters. The BPRC should review the standard control procedures in some detail to ensure that they are sufficiently refined and determine if additions to them might be made to better deal with the unexpected during their implementation. The committee should also focus attention on the frequency and degree of training, the extent of on-site BOP and kick-control drills, and the matter of crew meetings necessary to ensure maximum efficiency when kicks are encountered.

The Panel also believes the committee should look at the level of expertise necessary during particularly crucial phases at critical sour wells. The need for a special expertise, in addition to that provided by the drilling foremen, should be considered, along with the role of the back-up drilling foreman during emergencies, and any other steps that would ensure optimum decisions at important stages. The appropriateness of an increased role for the ERCB in terms of ensuring that kick-control procedures are adequate and rigidly adhered to should also be considered.

5.7 Summary of Panel's Views

On the basis of the foregoing analysis, the Panel concludes that the 13-12 well blew out because a series of sour gas kicks, which occurred while coring in the Nisku formation, were not controlled. It further concludes that no one element in the chain of events was the sole cause of the blowout.

The initial entry of reservoir fluids into the wellbore was probably due to a combination of a mud weight which provided only a modest overbalance and the crew not adequately recognizing the need for extreme caution under these circumstances and not adhering to sound drilling practices. Amoco's initial response to the first kick was inadequate, probably because it failed to realize it had a kick due to the failure of the casing pressure instruments.

If the degasser had operated effectively, the kick may have been circulated out of the system. Even with the failure of the degasser, control may have been maintained if there had been sufficient and properly weighted mud on hand to pump into the well. If the decision had been made to use H_2S resistant pipe for the full drill string, the pipe might not have parted and the well might not have blown out. Additionally, the failure of other equipment, such as the casing pressure instruments, the travelling block hook latch, and the kelly hose, played a role in the cause of the event.

With respect to Amoco, the Panel concludes that its judgement was reasonable with respect to the degasser design, and to a lesser extent, the choice of drill pipe, even though both of these elements failed and were causative factors in terms of the blowout. Such is not the case regarding the drilling practices followed while in the critical zone, the implementation of well-control procedures, plans to ensure the availability of adequate volumes of drilling mud in emergency circumstances, and the maintenance of equipment such as casing pressure instruments.

It is clear from the evidence at both phases of the inquiry that great care is necessary in the planning for and drilling of wells, particularly where sour gas may be involved. It is also evident that the human factor played a major role at Lodgepole, as appears to be the case at most blowouts. Extra effort is needed for critical sour wells to ensure that on-site personnel are well trained and continuously aware of the potential ramifications of a blowout or even a kick, and that special caution is taken to avoid them and to deal with unexpected problems. Special procedures should be developed and utilized to ensure this is done.

The Panel's review of the 13-12 incident indicates that Amoco did not take extra steps to ensure that all operations in the critical zone were in accordance with the highest of standards. Why this was not done is not clear, particularly having in mind that Amoco had experienced a blowout a few years earlier in a nearby well, and consequently knew the potential danger of drilling in the area.

The Panel believes that Amoco should review, at a very senior level, the policies and procedures that apply to the drilling of critical sour wells, to ensure that the lessons of the Lodgepole blowout are fully recognized in the planning for such wells and in the execution of those plans. The Panel believes that the ERCB should do likewise and indeed knows that the ERCB has under way a detailed review of drilling practices for sour wells, through the BPRC. The Panel fully supports on-going efforts in that regard.

5.8 Recommendations

The Panel believes that the following matters involved in the cause of the 13-12 blowout need further investigation. Many of these are already being looked at by the BPRC as a result of Phase 2 of the inquiry.

1 The following types of equipment should be examined for design, capacity, and operational problems to ensure that they are adequate for worst-case conditions:
   (a) degasser,
   (b) casing pressure instruments,
   (c) travelling block hook latch,
   (d) kelly hose,
   (e) blowout preventers, and
   (f) equipment for anchoring drill pipe.

2 The BPRC should examine the impact of H_2S, and how to avoid those impacts on:
   (a) drill pipe,
   (b) external BOP components, and
   (c) BOP master controls.

3 The industry and ERCB should take any action necessary to ensure that drilling operations are carried out in a cautious manner particularly in the critical zone of critical sour wells. Special procedures should be developed, documented, and used for operations in the critical zone. These would include detailed instructions respecting tripping in, tripping out, coring, testing, and other operations where particular care is required.

4 Standard kick-control procedures should be reviewed to determine whether they allow for situations where equipment failures or other unexpected events occur during control operations.

5 The adequacy of the current training programs for drilling personnel should be reviewed and particular consideration should be given to ensuring that they are effective in ensuring crew familiarity with kick recognition and control.

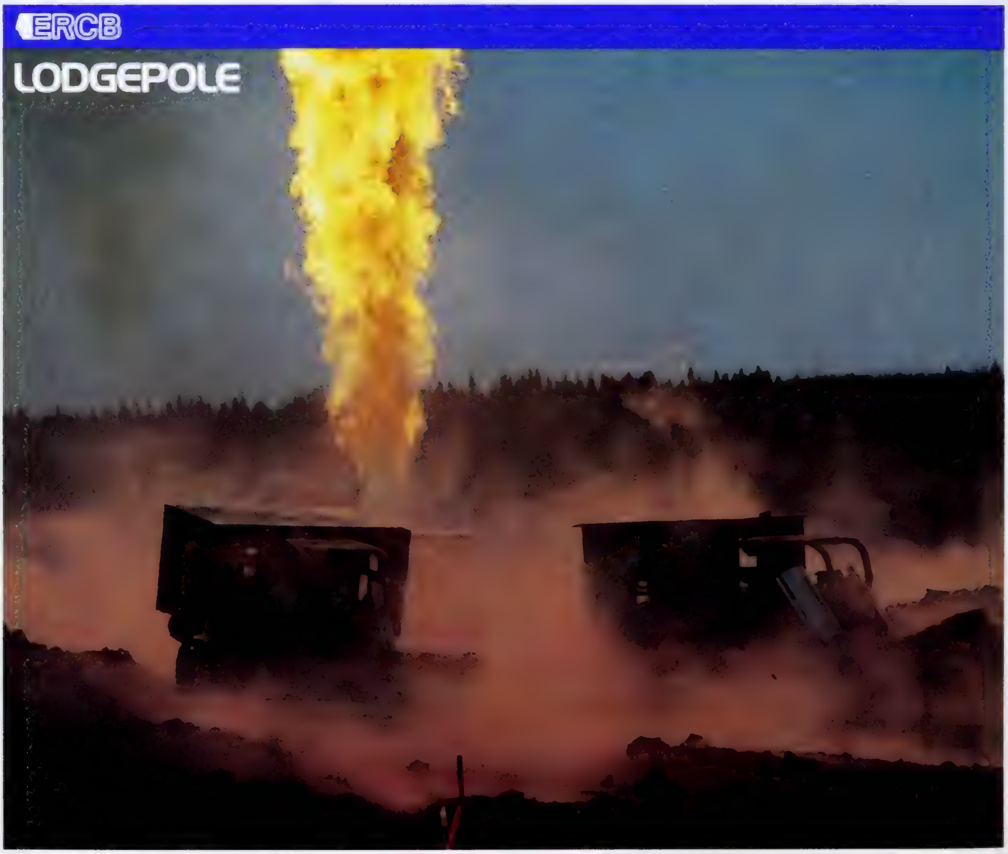
6 Consideration should be given to the need to have special expertise available while operations are being conducted in the critical zone of critical sour wells.

7 The ERCB should review its inspection system and in particular should conduct special inspections of critical sour wells immediately prior to entry of the critical zone and while drilling in it, to ensure that operations are being conducted in a cautious manner and consistent with proper procedures.

8 Mud system design and operation should be reviewed respecting density, system capacity, back-up supply, scavengers, and impact of H_2S on mud and the ability to pretreat and recondition it.

9 Occupational Health and Safety (OH&S) should consider amending its regulations to ensure that breathing apparatus is available for all individuals that may be at a rig, including extra people called in for an emergency.

6



Heat-shielded tractors prepare the site for well capping operations.

Photo credit: W. Wylie, ERCB

6 WELL-CONTROL ACTIVITIES AND THE ADEQUACY OF ACTIONS BY AMOCO AND OTHERS

6.1 Introduction

Once a blowout has occurred, there are several factors which influence the length of time it will take to regain control. Appendix 3 of the Phase 2 report provides details of the 21 blowouts that have occurred in Alberta during the period 1974 to 1983. The duration of the uncontrolled flow of those wells ranged from a few hours to the 67 days for the 13-12 well. The average duration was about 10 days. There are, of course, major differences between the "characteristics" of the 21 blowout cases. One of the objectives of this section is to examine the factors that have the most influence on the difficulties involved in regaining well control and thus on the blowout duration. The section also examines the question of whether Amoco's actions while attempting to gain control were appropriate. The assessment is based upon information that was available to Amoco at the time of the blowout, rather than on knowledge gained as a result of it.

6.2 Blowout Characteristics

The characteristics of a blowout which have the greatest bearing on its duration are the magnitude of the flow, the H_2S and liquid content of the well effluent, the condition of the wellhead and blowout control equipment, and the weather or atmospheric conditions with which the well control specialists must contend.

A review of the blowout wells listed in the Phase 2 report indicates that the 13-12 well blowout generally exhibited characteristics which were among the most severe in terms of problems which had to be dealt with during control operations.

The 13-12 well was flowing gas at a very high rate, probably more than 1.4×10^6 m^3 per day, and this by itself would present problems in regaining control. The flow rate was not accurately estimated in the initial stages and efforts should be made to ensure that, in future situations, the most accurate estimate practical is made at an early stage. The high flow rate was also a direct reflection of the high pressure and the need for greater strength in the well-control equipment. The more serious aspects of the flow, however, were its high H_2S and condensate content. The very high H_2S content, estimated at the inquiry to be 25 per cent, not only posed a serious safety hazard to the on-site workers when the well was not on fire, but it also meant that all of the equipment used was subjected to very corrosive gas and liquids.

The estimated hydrocarbon liquid content of the gas was such that about 1100 m^3 per day of condensate may have been emitted. During the period the well was not burning, most of the condensate settled on the well site and immediate surrounding area creating a very dangerous and slippery environment in which the well-control operations had to take place.

The fact that the blowout had occurred through the drill pipe and that it had broken off above the floor also complicated control procedures and very much limited the type of action that could be taken. The presence of the drill pipe in the BOP stack prevented well control by closing the blind rams. At the same time, closing the pipe rams did not accomplish well control, as the well effluent continued to blow out through the drill pipe.

The process of regaining control of the well was also significantly affected by atmospheric conditions. Indeed, the weather appears to have been particularly important for the 13-12 well because of the high H_2S and condensate content. Unless there was a reasonably steady breeze to help clear the site of H_2S, it was not possible to work. During the period of the blowout, there were about 10.5 days when atmospheric conditions were unfavourable and prevented full activity.

Amoco was faced with a difficult well to control and the extreme characteristics of the blowout were clearly beyond Amoco's control once the well had blown out. The Panel questions, however, whether Amoco, and indeed other parties involved in the control operation, fully appreciated the magnitude of the problems. Evidence of this appears in the initial and on-going expectations that the well would be controlled in a matter of a few more days.

6.3 Appropriateness of Control Plans

Once a blowout has occurred, the most important factor in regaining control is the development and implementation of suitable control plans. Planning was particularly important for the 13-12 well because of its very difficult characteristics.

6.3.1 Emergency Response Plan

Amoco has a "Major Wellsite Incident Response Plan", which was activated on 17 October 1982 when the 13-12 well went out of control. The high H_2S content of the well effluent meant the situation was a Condition IV, which is the most extreme recognized in the plan. The response plan is not site-specific and so did not provide for specific measures to control the well. It did, however, result in immediate notification of senior Amoco personnel and the ERCB. Amoco then engaged a well-control specialist team, Wild Well Control Inc.

Within 48 hours of the blowout, Amoco had put together a group which included its own local people, Amoco's management personnel, wild well specialists from Amoco's parent organization, well-control specialists from

Wild Well, and safety and other service personnel. During the early period of the blowout, Nabors' personnel attended planning meetings. Alternative plans to cap the well were discussed and a preferred sequence was established. The group, along with ERCB personnel, met almost daily throughout the period of the blowout and continuously reviewed and updated the plans for control of the well. When critical procedures were to be carried out, detailed planning meetings took place to ensure that each individual knew his responsibility.

The Panel considers that the contingency planning as it related to control of the well and subsequent planning of the actual methods to be used was carried out reasonably well and co-ordinated in an acceptable manner between the operator, its control specialists, and the ERCB. Most of the serious problems encountered did not result from deficiencies in planning, although the chances of some of them occurring might have been modestly reduced with greater attention to detail in the planning process. Experience gained in this incident should be put to use in future situations and one valuable lesson gained is the need for extreme detail in planning the control procedures. The availability of medical expertise and advice would assist in ensuring satisfactory arrangements for breathing equipment, on-site treatment in the event of accidents, and evacuation procedures for workers.

6.3.2 Plan A

The initial plan to control the well, which is illustrated in Figure 6.1, involved lowering a new blowout preventer over the drill pipe and bolting it into place. It failed because an automatic pipe cleaner, the presence of which had been forgotten, was in place on the rig and it constricted the size of the available opening.

Failure to remember the pipe cleaner was an unfortunate human error which might have been avoided if the planning sessions had included all personnel previously involved with the rig and had incorporated a pictorial reproduction of every element of the rig. If the existence of the pipe stripper had been recalled, it would likely have reduced the duration of the blowout by a couple of days.

6.3.3 Plan B

The next plan involved opening the pipe rams in the BOP which were closed around the pipe in the hole. This would allow the pipe to drop, as Amoco expected would happen, or result in it blowing out of the hole because of pressure from the formation. The blind rams would then be closed to control the well as shown in Figure 6.2. When the pipe rams were opened, the pipe blew out of the hole, created sparks, and started the first fire. The blind rams did not close and Plan B failed. The reason the blind rams did not close is not known, but it may have been because the fire quickly destroyed the hydraulic hoses.

In the Panel's judgement, this method was appropriate to apply at that particular time, and even if it had been clear that the pipe would blow out, it would likely have been attempted. The use of flexible hose for the hydraulic lines and the short time which it took for the fire to destroy them was a problem, but not one primarily related to planning. Amoco and its specialists had carefully considered that matter and made the decision they considered best in the circumstances.

6.3.4 Plan C

The next plan is illustrated in Figures 6.3 and 6.4. It involved extinguishing the fire and lowering a new control assembly over the casing. The process was interrupted by an accident which resulted in the death of two workers. A critical seal in the control assembly was damaged during or following the accident. The damage was not noticed until 2 days later when control activities resumed. The well caught fire a second time before control procedures could be repeated with a new seal.

The Panel is satisfied that this was an appropriate procedure to attempt and that it was planned in some detail. It is possible however that greater detail in the planning and particularly a rehearsal of actions that would be taken in the event of a serious mishap might have reduced the seriousness of the problem. Safety matters are discussed further in section 6.4.

6.3.5 The Successful Plan

The well was finally controlled by lowering a new BOP assembly onto the casing and attaching it while the well was burning, as illustrated in Figures 6.5 and 6.6. This operation was carried out by Boots and Coots Inc.

There is no evidence to indicate that the change that Amoco made in its control experts for this final and successful capping attempt related to any lack of planning. Rather, Amoco had decided, as a result of damage to the casing bowl from the second fire and pressure from the public and the ERCB, that an attempt should be made to control the well while it was on fire. Such a procedure had only been successfully carried out six times in the world. Wild Well declined to attempt it and Amoco engaged a new specialist control team.

6.3.6 The Relief Hole Plan

An alternative plan involved drilling a relief hole as illustrated in Figure 6.7 and attempting to approach the wellbore of the 13-12 well just above the Nisku reef. Communication would then have to be established between the two wellbores. The flow would be stopped by injecting fluids through the relief hole into the 13-12 wellbore. Experience at other wells has shown this method of well control is not always successful. A surface lease was prepared but drilling of the well was not initiated.

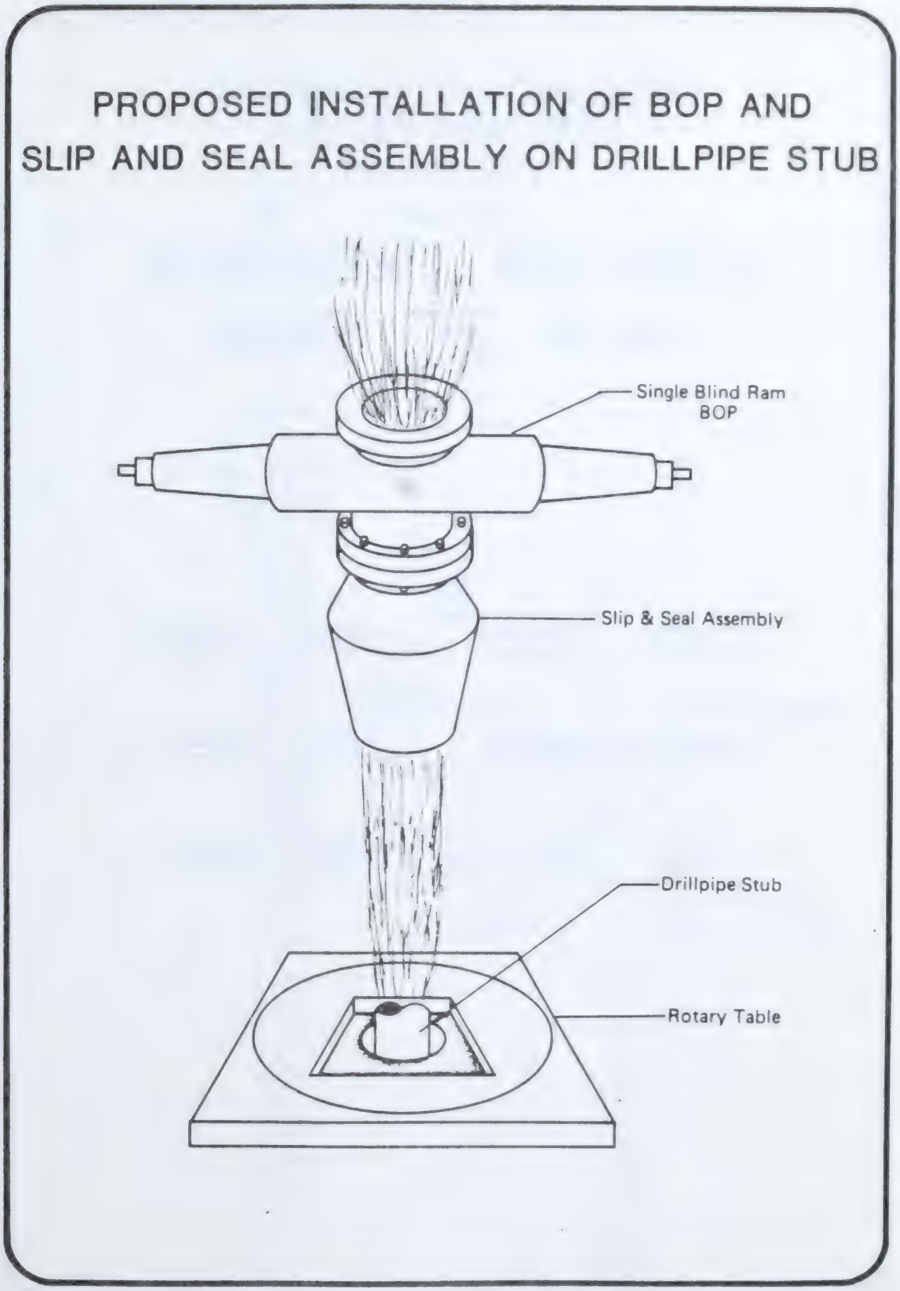

PROPOSED INSTALLATION OF BOP AND SLIP AND SEAL ASSEMBLY ON DRILLPIPE STUB
Single Blind Ram BOP
Slip & Seal Assembly
Drillpipe Stub
Rotary Table

FIGURE 6.1 AMOCO'S DIAGRAM OF PROPOSED INSTALLATION OF BOP (PLAN "A").
Reproduced from Exhibit No. 66.

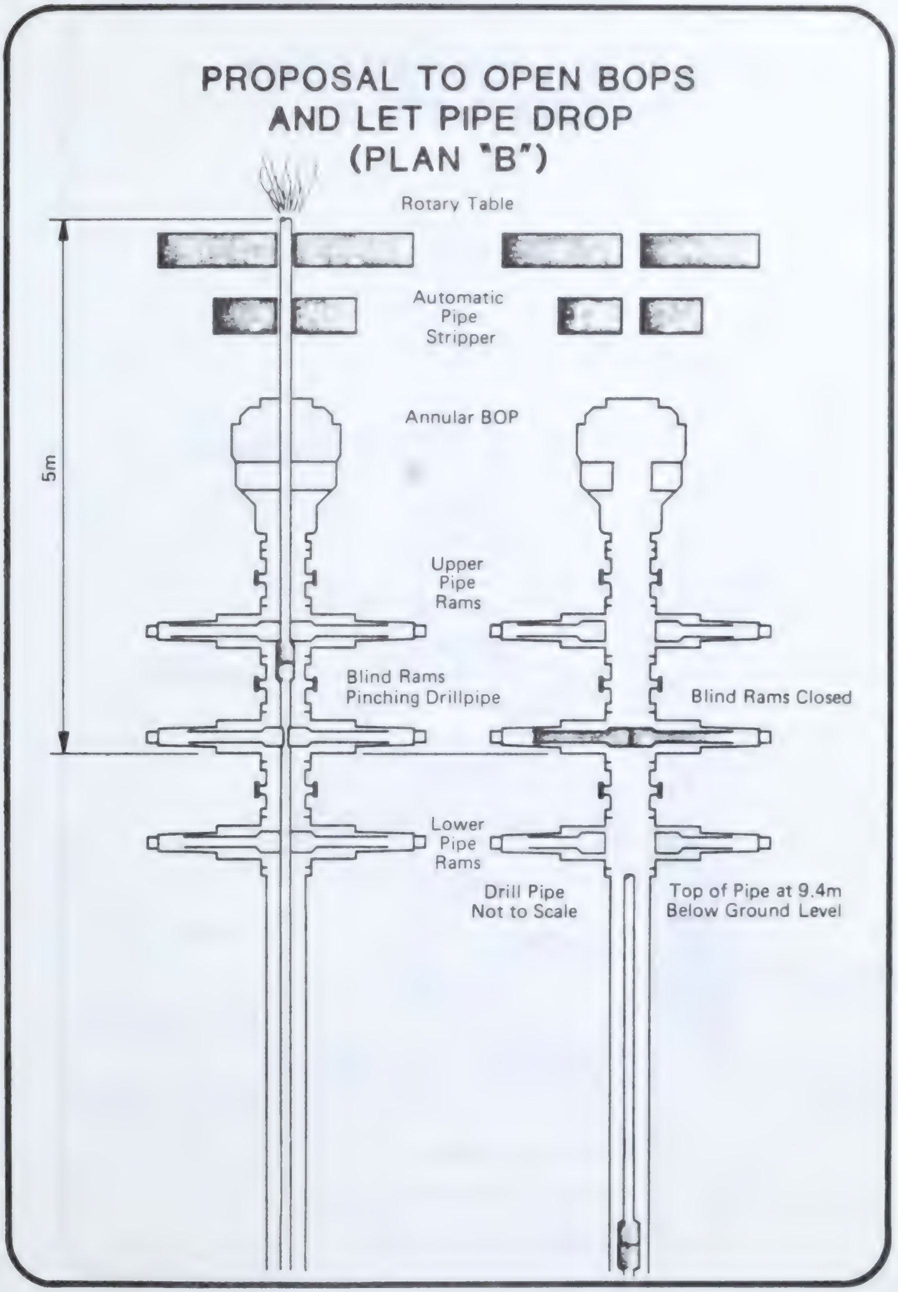


FIGURE 6.2 AMOCO'S DIAGRAM OF PROPOSAL TO OPEN BOPS AND LET PIPE DROP (PLAN"B"). Reproduced from Exhibit No. 66.

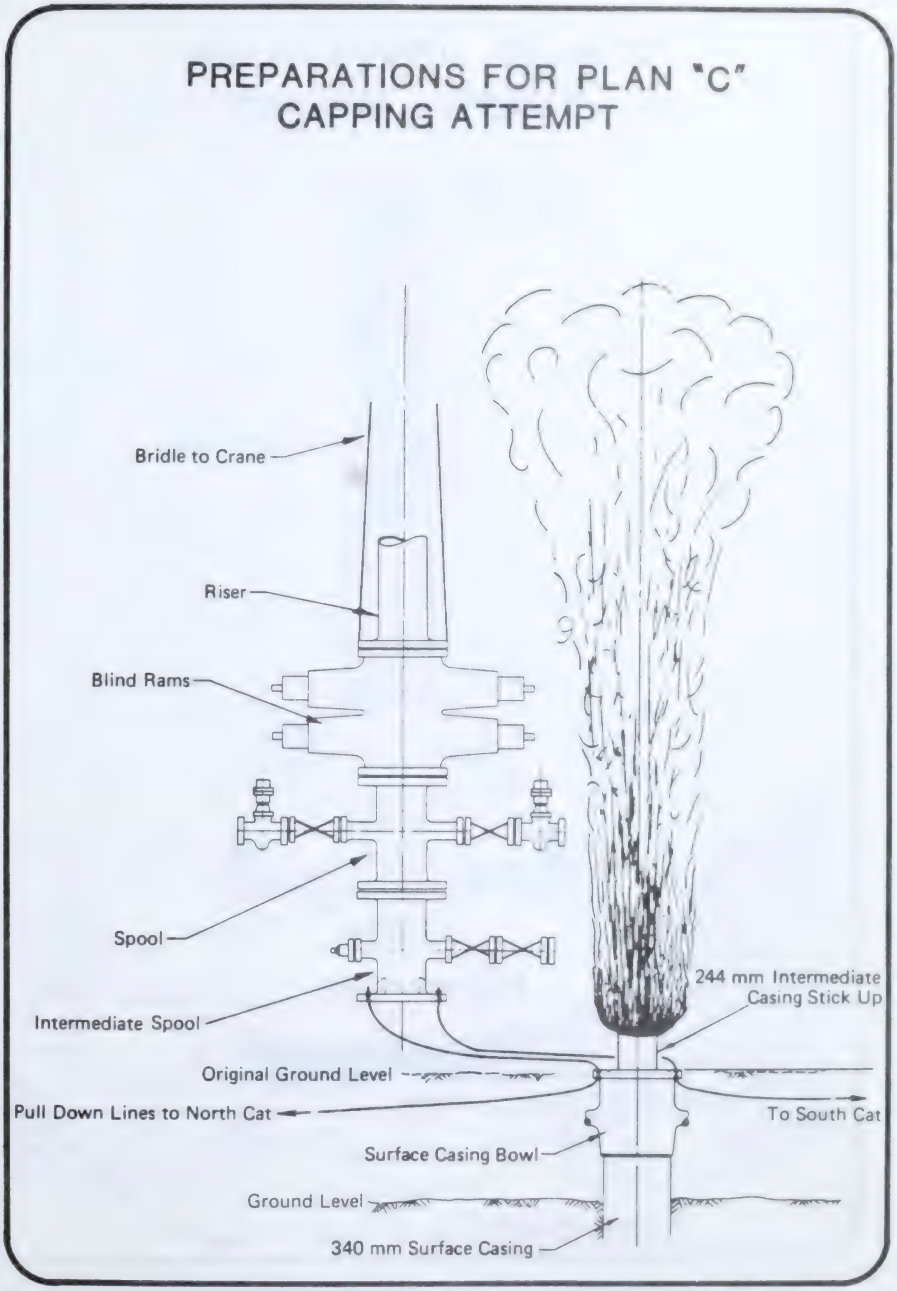


FIGURE 6.3 AMOCO'S DIAGRAM OF PREPARATIONS FOR PLAN "C" CAPPING ATTEMPT.
Reproduced from Exhibit No. 66.

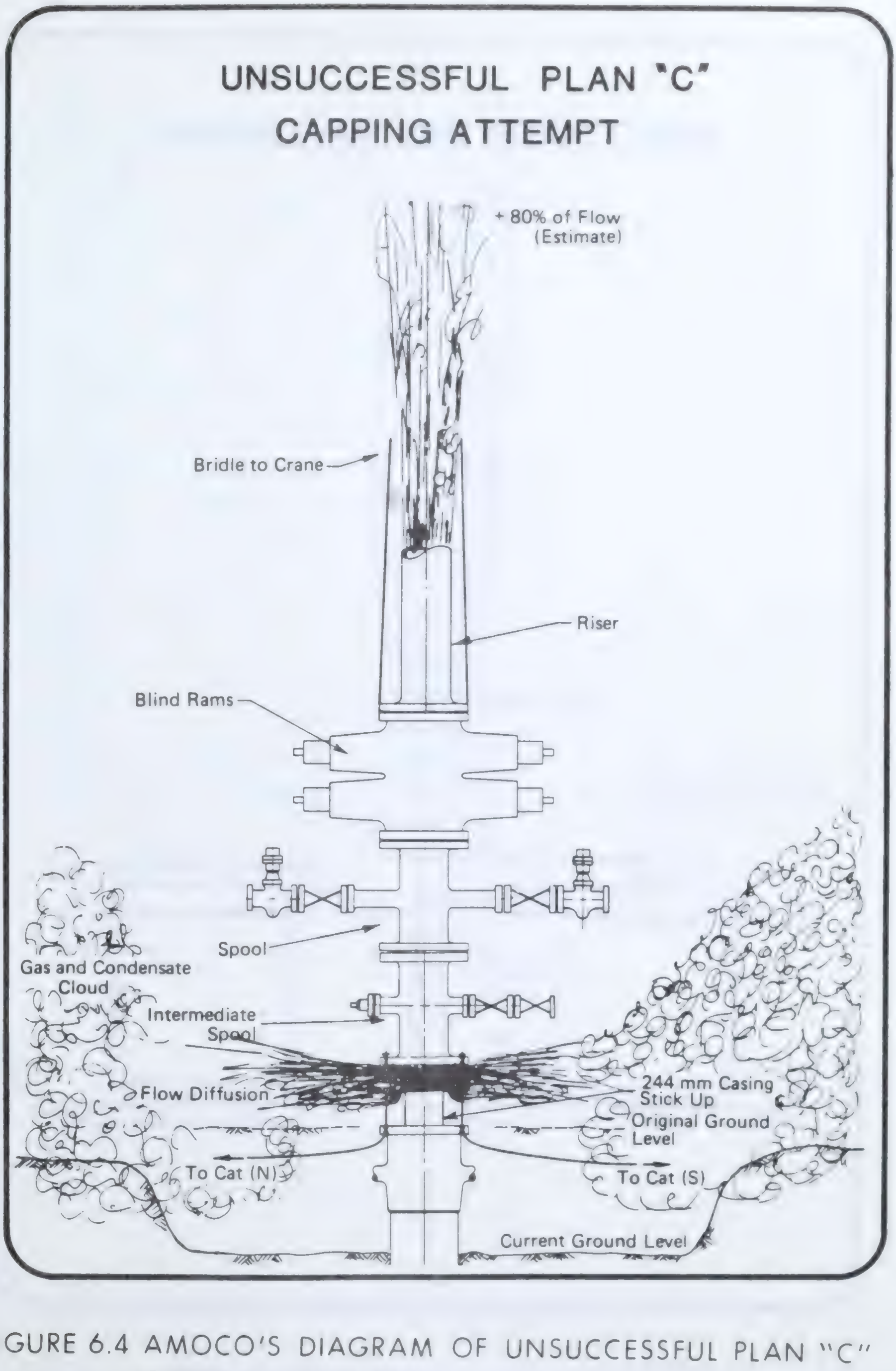


FIGURE 6.4 AMOCO'S DIAGRAM OF UNSUCCESSFUL PLAN "C" CAPPING ATTEMPT.
Reproduced from Exhibit No. 66.

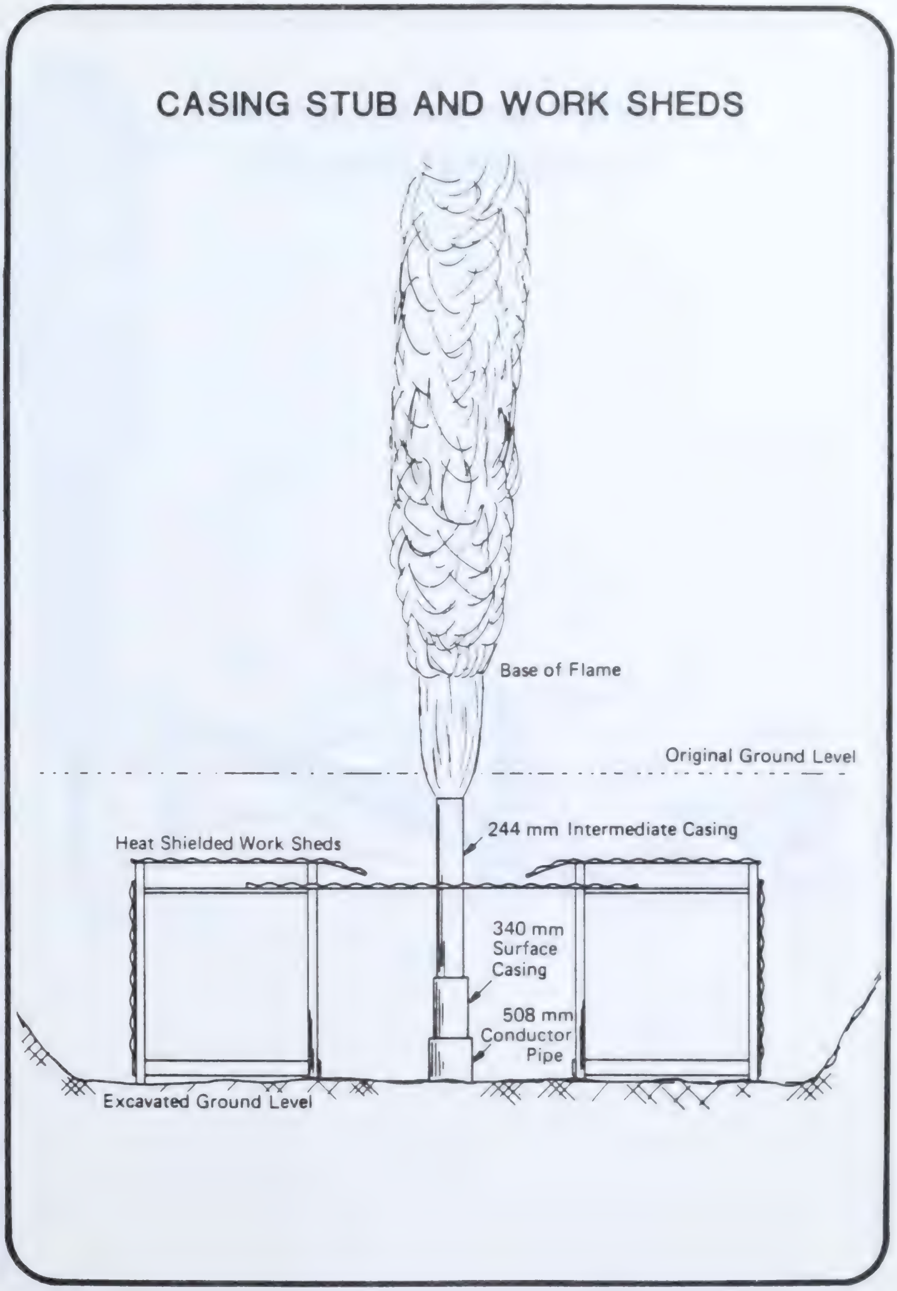


FIGURE 6.5 AMOCO'S DIAGRAM OF CASING STUB AND WORK SHEDS.
Reproduced from Exhibit No.66.

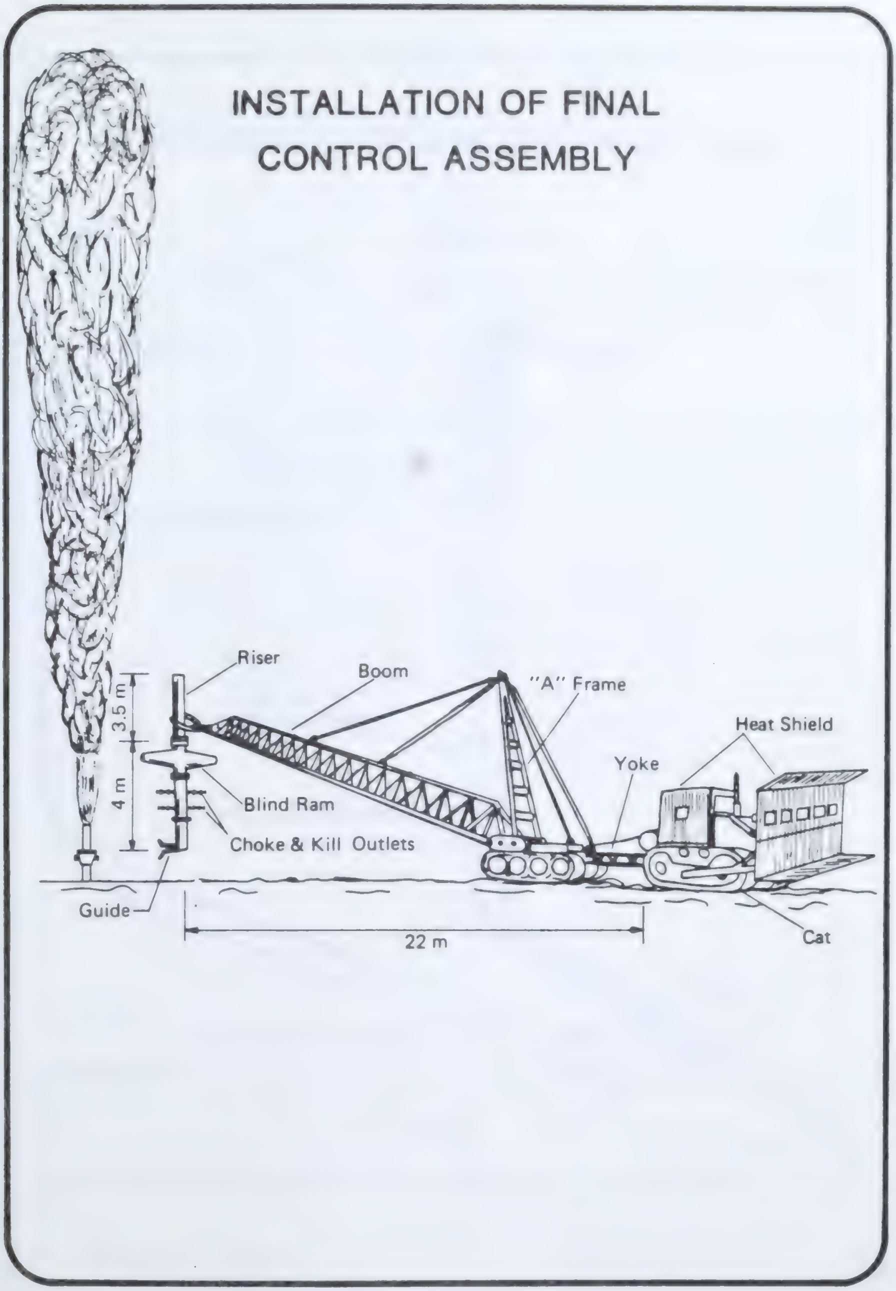


FIGURE 6.6 AMOCO'S DIAGRAM OF INSTALLATION OF FINAL CONTROL ASSEMBLY.

Reproduced from Exhibit No. 66.

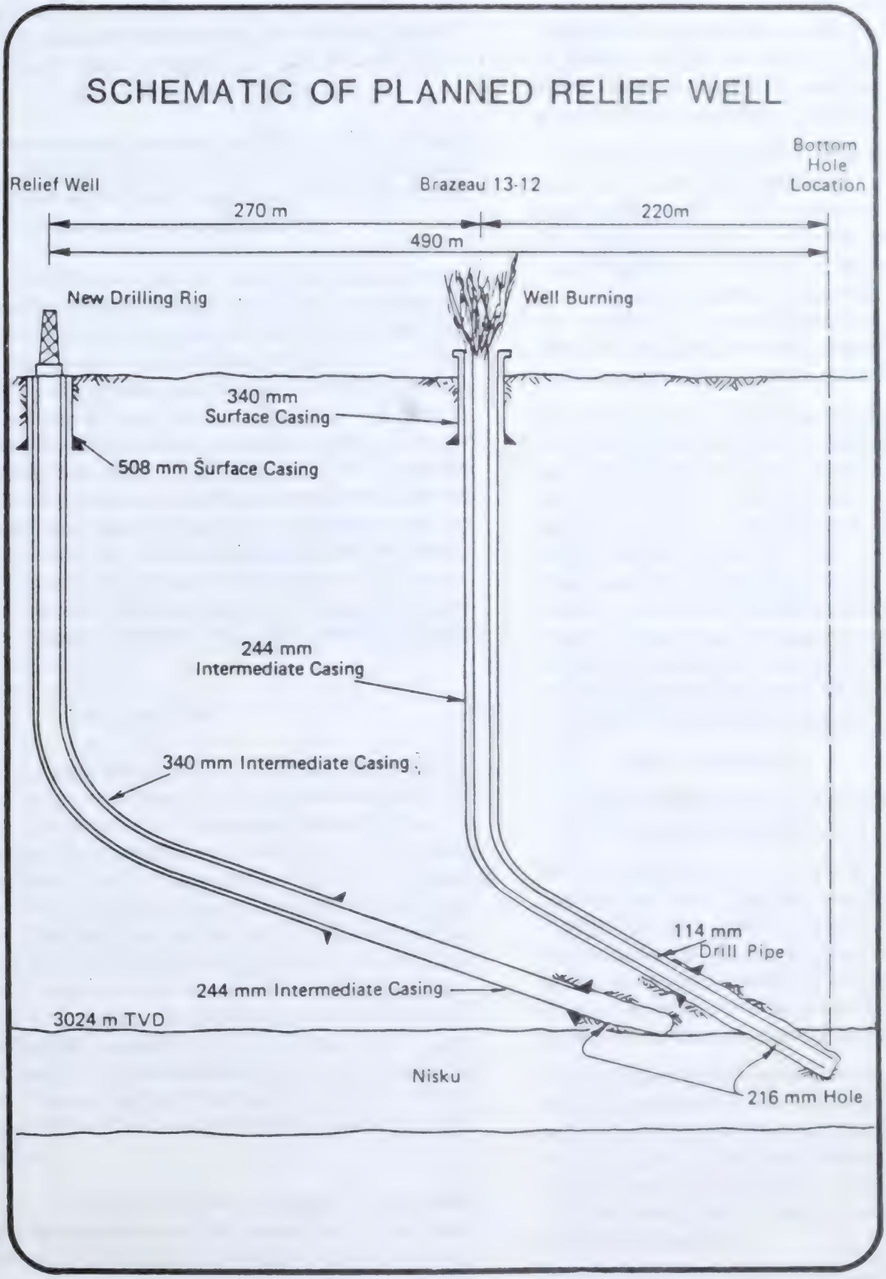


FIGURE 6.7 AMOCO'S SCHEMATIC OF PLANNED RELIEF WELL.
Reproduced from Exhibit No.146.

Amoco's position respecting the relief hole was that it should be a last resort because it would take up to 3 months to drill and then the chance of success was not as good as for a kill from the surface of the wild well (top kill). Amoco, however, prepared a site and placed a rig on standby for the drilling of the relief well.

Amoco contended that once the drilling of the relief well had commenced, top kill attempts would have to cease because the 13-12 well would have to be on fire for the safety of the men on the relief hole rig.

The Panel believes, on the basis of the evidence before it, that the ERCB's role in the decisions respecting the relief hole should be more formalized. The Panel is satisfied that ERCB representatives were aware of, and in accord with, the on-going decision not to proceed with the relief hole throughout the duration of the incident. Consideration should be given, however, to putting in place a process whereby the need for drilling a relief well would be reviewed on a detailed basis if a top control method proved unsuccessful, and to documenting in detail the reasons for the decisions. The process should also ensure that the decision makers are fully aware of the impacts the blowout is having on the public so that this aspect may be fully considered along with others. This matter is discussed further in section 6.3.7.

6.3.7 Igniting the Well

Amoco stated that it did not intentionally ignite the well because there was not a serious hazard to the public and igniting the well would have significantly reduced the chances of accomplishing a successful top kill in a short time period. The Panel agrees that at the time the decision was being made there was reason to believe this to be the case. The Panel does not believe the immediate ignition of the 13-12 well was necessary, however, it does consider that in certain circumstances ignition should take place. Such a circumstance could have occurred if H_2S levels had reached evacuation limits at Drayton Valley, where evacuation, due to the number of people, was not practical. The evidence suggests that the well would have been ignited if there had been any serious potential hazard to the town.

Although the Panel accepts that igniting a well would typically make it more difficult to effect a top kill and would present a more serious safety risk to on-site workers, it notes that the 13-12 well was eventually controlled while on fire. The success in this instance, along with the increased difficulties and risk, must be balanced if future blowouts result in a situation where the need to ignite a well, for public safety or comfort reasons, is being considered.

The Panel, in the Phase 2 report, recommended that the ERCB require an emergency response plan for all critical sour wells and that the plan deal with the manner in which the decision would be made as to whether a blowout should be ignited. This recommendation is affirmed and should assist in ensuring that the matter of intentionally igniting a well will be adequately dealt with in future.

As was the case with respect to the relief well, the Panel believes that the ERCB involvement in decisions not to ignite the well was not as formalized as it might have been. The Panel believes that in future, the ERCB should establish a formal review process that would consider the merits of igniting the well, throughout a blowout episode, and document the reasons for deciding whether or not to do so. In making this decision, all aspects of the matter, including impact on the public, must be considered.

The decision process respecting ignition, and also that respecting a relief well, must include an opportunity for the public to make their concerns known. The manner in which this would be done is important because it must allow for timely on-going decisions. The Panel recommends that the ERCB and other involved parties, in formulating plans for handling possible serious blowouts in future, consider this matter carefully and properly provide for public input. The system must also ensure that decisions respecting intentional ignition of a well or drilling a relief well are made known to the public along with the rationale for the decisions reached.

6.4 Control Equipment

A successful control operation requires specialized equipment to be promptly available.

Amoco was able to have on site all of the equipment necessary to control the well essentially when it was needed. This was possible, in part, because Amoco is a large international organization and was able to call on tremendous resources to assist. For example, Amoco had its own aircraft fly in necessary equipment from areas as far away as the Canadian East Coast and the Beaufort Sea.

One equipment problem which did occur resulted from the need to establish a new BOP master-control station at the edge of the lease because the original station was in the doghouse and had been exposed to high levels of H_2S. The station was needed for the control Plan B which involved opening the pipe rams to drop the pipe and then closing the blind rams.

The new station made it necessary to install new hydraulic lines to the BOPs and the decision was made to use flexible hose for ease of handling in the slippery and dangerous atmosphere under the substructure. The lines failed almost instantly during the ensuing fire and the blind rams did not close. However, it is not known for certain that the failure to close was as a result of the hydraulic lines burning quickly. In any case, the Panel is satisfied that the rationale used by the control experts in their choice of line was reasonable in the circumstances. This is an area where the experience gained in the Lodgepole incident may be of assistance if similar situations arise in future.

The Panel is satisfied that appropriate equipment was brought in or fabricated as required, promptly and without regard to cost, and that Amoco used whatever was needed of its considerable resources and international organization to obtain equipment. Indeed, the Panel, having heard much evidence respecting the resources that Amoco was forced to call upon in an effort to control the well and handle other aspects of the blowout, is concerned that a small organization, if faced with a similar situation, might not be able to handle it adequately. For this reason, the Panel believes the ERCB should consider the availability of blowout insurance or other measures which would safeguard the public purse against having to cover the costs of a major blowout. Consideration should also be given to ways in which the experience and expertise which a major company is able to bring to bear, because of its extensive operations, could be made available if a small organization experienced a serious blowout.

6.5 Safety Equipment and Procedures

The control operations required not only specialized control equipment and expertise, but due to the extreme hazard that resulted from the high H_2S and condensate content, on-site safety matters also played a key role in the operations.

Amoco stated that immediately following the blowout, it engaged the services of safety experts. Safety personnel were at the site at all times and they decided, on the basis of weather conditions and H_2S monitoring results, when control operations could be carried out. The position of Amoco was that safety aspects of the operation were effective notwithstanding that a serious accident occurred on 16 November.

The Panel is of the view that it was proper for Amoco to contract for the services of safety experts although Amoco had the final responsibility for the safety of the workers. The safety procedures apparently worked for most of the blowout period. However, there was a serious accident which resulted in the death of two workers, during an attempt to cap the well on 16 November. During this accident, three other men were rendered unconscious, and two more were affected by the gas. This clearly was a failure in terms of the safety system and brought out serious fundamental deficiencies in it. One of the deaths was the subject of an inquiry under the Fatality Inquiries Act and consideration of the deaths themselves was excluded from the terms of reference for the inquiry being dealt with in this report. However, the Panel believes it is impossible to consider "all aspects of occupational health and safety but excluding the two fatalities" without giving some recognition to safety equipment and procedures in use when the accident occurred. It has therefore drawn on the fatality inquiry evidence, which is on the public record, for that purpose.

The inexplicable removal of a breathing mask by at least one worker who was killed and the contamination of the masks of other workers raises the question of the leakage of gas into the face piece of the demand masks which were used. Although these masks met the requirements of OH&S, they had only a protection factor of 50. It is known that the death of humans can occur quickly at H_2S concentrations of 1000 to 1500 ppm, and that the concentration of the gas flowing from the 13-12 well was about 25 per cent or 250 000 ppm. Thus, when the upward rise of the gas was deflected, if air mixing was not sufficient to dilute the H_2S at ground level, the maximum protection factor of 50 would be exceeded. It is noteworthy that positive pressure breathing type masks have been recommended by the National Fire Protection Agency since 1981. Following the accident, OH&S ordered that masks with a positive pressure air supply be used in place of the demand type. Amoco's Major Wellsite Incident Response Plan, in reference material API Recommended Practices API RP 49, section 8.2(a), recommended the use of "pressure demand" masks. It may be that some confusion of the meaning of this term had some effect on the selection of the inadequate "demand" masks by Amoco for use in the capping operations.

The actions which several workers took, or were compelled to take, during the accident were not in accord with generally accepted safety procedures. Most striking was their inappropriate use of the 5-minute escape bottles created by the stress of the accident. Another safety problem which occurred during the 16 November accident related to the apparent inability of those on site to evacuate stricken workers from the extremely treacherous and high hazard zone within 20 or so metres of the wellhead. This might have been avoided by detailed planning of every aspect of a possible emergency situation. Such planning would have to include an exploration of methods for dragging unconscious men in prevailing slippery conditions, a system for communication in a gas cloud, the need for safety lines or dragging sheets, and the appropriate use of emergency air bottles for carrying out rescue.

Prior to 16 November, safety planning for possible emergencies did not deal with the kinds of details mentioned above. There is no evidence that this occurred to save time or money. Detailed written safety procedures were developed and implemented before work at the well site resumed following the 16 November accident. The

Panel believes that these procedures must be reviewed for possible improvement. In addition, the appropriate safety roles of government, industry, and safety specialists should be examined further.

6.6 The Human Factor

The human factor played a role in many of the matters dealt with earlier in this section. The Panel believes it worthwhile, however, to make a further comment respecting this factor.

The personnel involved in the efforts to control the well included Amoco workers, some Nabors people, the well control specialists, and other service personnel under contract to Amoco. The Panel is satisfied, that overall, these individuals were adequately trained and had experience consistent with their role in the process.

Some media reports at the time of the blowout suggested that Amoco's replacement of the well control team was a tacit admission that it had been mistaken in the first instance by engaging an inexperienced team. As indicated previously, the Panel heard no evidence to support that position and accepts Amoco's explanation that Wild Well was replaced because it was not prepared to cap the well while it was burning.

6.7 Summary of Panel's Views

The overall general contingency plan which Amoco had in place was satisfactory. Although the plan was not detailed nor site-specific, it worked reasonably well for well-control operations because it brought together those persons who had the knowledge and the authority to implement any action necessary. The plan also generally identified the responsibilities of each party and provided for an on-going planning process which was well co-ordinated and generally effective in most respects. One notable exception was lack of sufficient detail in establishing Plan A, and thus overlooking the existence of the automatic pipe cleaner on the rig. In addition, there is clearly a need for a site-specific emergency plan for critical sour wells. This is discussed in section 7.5.

It took 67 days to control the 13-12 blowout primarily because of the well's characteristics which were particularly severe. They included a very high flow rate with very high H_2S and condensate content which, when coupled with unfavourable weather conditions over part of the period of the blowout, resulted in a dangerous and difficult working environment for those attempting to control the well. These matters were beyond Amoco's control but there are indications that the seriousness of them was not fully appreciated by Amoco and others, including the ERCB. An illustration of this related to safety matters where Amoco employed equipment and procedures which appeared to be typical of the industry. In this case, because of the very severe conditions, a serious accident occurred which substantially delayed capping of the well.

The panel is satisfied that Amoco demonstrated a full commitment to the task of restoring control at the well. There is no evidence that any of its decisions were governed by costs or factors other than an intent to control the well as soon as reasonably possible. It is true that several attempted procedures did not succeed, and indeed a combination of unfortunate occurrences meant that the blowout extended for a much longer period than would normally be expected

The initial and on-going decisions not to intentionally ignite the well, and either attempt to cap it while on fire or proceed with the actual drilling of the relief well, were appropriate given the circumstances that existed. However, the involvement of the ERCB in those decisions might have been more formalized and it should have given more specific attention to impacts which were occurring on the public. A system is needed to ensure that all aspects of such decisions, including impact on the public, are carefully considered and that the decision and supporting reasons are communicated to the public.

The Panel is concerned that a small organization experiencing a similar blowout might not have the resources and expertise that Amoco was able to mobilize for the 13-12 well blowout. Therefore, it believes the ERCB should investigate this matter further, including the feasibility of requiring blowout insurance.

The Panel is generally satisfied that the personnel involved in efforts to control the well were properly trained and that they had the appropriate experience to undertake the necessary operations. However, it is not satisfied that Amoco's planning process was sufficiently detailed with respect to occupational health and safety, particularly as it related to handling extreme emergency situations. Additionally, the Panel is concerned that the role of OH&S was not sufficiently pro-active during planning of the control procedures. The Panel believes that further work is required by government and industry to ensure that safety matters are adequately dealt with in similar future situations should they occur.

6.8 Recommendations

After considering the evidence respecting efforts to control the well, the Panel makes the following recommendations:

1 The ERCB and the involved operator should make a serious effort at the outset of any blowout to ensure that the flow rate and other characteristics are estimated as accurately as possible, and that the estimates and the expected weather conditions are properly recognized in planning for control of the well.

2 The ERCB should formalize, to a greater extent, its involvement in decisions related to intentionally ignit-

ing blowouts and the possible drilling of relief wells. A process should be developed that would ensure that public concerns are properly considered in making these decisions, and the reasons for the decisions are communicated to the public.

3 OH&S should give consideration to the establishment of a committee to be concerned with protecting workers in toxic gas environments such as would result from episodes like the 13-12 blowout. Such a committee might be composed of experts on safety and rescue drawn from OH&S, the petroleum industry, the ERCB, and the Calgary and Edmonton fire departments. These individuals, or a team which they could assemble, could be readily available to act as advisers or participants in the management of the safety aspects of particularly dangerous situations in the petroleum industry. With respect to the prevention of serious accidents, they could assist in reviewing current and future safety and rescue practices and safety educational programs.

4 OH&S should give consideration to the development of an adequate, possibly compulsory, training program for workers who might encounter H_2S or other toxic gases in substantial amounts. The training would be needed prior to their involvement at a well site or other potentially dangerous locations. This training should emphasize practical matters such as familiarization with and the wearing of a self-contained breathing apparatus. Through such a program, workers who are physically or psychologically unsuitable for work in such hazardous environments, or while wearing masks, would likely be identified.

5 The ERCB should investigate the availability and limitations of blowout insurance. The Panel understands that the matter of insurance is being looked at by the ERCB as a result of the Phase 2 report.

6 The ERCB should consider how the experience and expertise needed to control a blowout would always be available when required, even by a small organization.

7 OH&S should pursue the development of clearly distinguishable names for all types of masks to be used in the presence of various concentrations of H_2S.

8 Consideration should be given by industry and the ERCB to the development of a workshop or seminar to consider technical matters related to the control of wild wells.

7

Alberta Environment's mobile air monitoring laboratory.

Photo courtesy Alberta Environment

7 HAZARD TO HUMAN HEALTH

7.1 Introduction

One of the issues of primary concern to the public, particularly those residing in the immediate area of the well, was the effect of the blowout on their health. Evidence respecting health effects was presented by some of the local residents and by a group of Edmonton respiratory patients. Additionally, studies were presented which were conducted by various groups or individuals to learn about the concerns of larger segments of the public. There was considerable discussion at the inquiry respecting the standards and suitability of H_2S exposure limits. The question of how the monitoring was carried out and whether those standards were exceeded also received much attention. This section of the report reviews each of these matters.

7.2 Medical Evidence

The Panel was not presented with any medical studies, and only one veterinary medical study of the effects of the Lodgepole blowout which could be considered to be scientific, because scientific data was not available to compile such studies. Furthermore, there are few epidemiological studies in the medical literature which are applicable to the affected local and distant communities. Nevertheless, a great deal of other information was presented bearing on the health of people and animals in areas close to Lodgepole.

7.2.1 General Effect on Local Population

The most useful medical data was given by 30 residents, mainly from farm families widely separated from each other within 50 km of the blowout site. The location of their residences is shown on Figure 7.1. They described the effect of this event on themselves and their families, and said their symptoms had an onset coincidental with the blowout. These included headache, eye irritation, upper respiratory tract symptoms such as sore throat, nasal irritation, and nosebleeds in children, lower respiratory tract symptoms including pain on deep inhalation and some shortness of breath. Gastrointestinal problems such as loss of appetite, nausea, and diarrhea were also described. An interpretation of these symptoms suggests that some could be related to irritation of exposed mucous membranes or gastrointestinal dysfunction, while other symptoms such as headache cannot be identified with dysfunction of one organ system.

These complaints were said to improve within 24 hours in people who left the area and recurred within 24 hours when the same individuals returned during the time of the blowout. When the well was on fire, some people recalled improvement while others reported that they suffered persistent symptoms. Complaints suggestive of central nervous system dysfunction were infrequent. During cross-examination, some of these individuals denied symptoms such as chills, generalized muscle aching, or some of the usual systemic complaints of an acute infectious process. PASGEC filed letters from three physicians describing similar symptoms during this period in patients from the same general area. These physicians attributed these medical findings to the gas in the environment. They did not make any assertions with respect to permanent symptoms or harm.

An attempt was made by the Panel to determine how representative this small group would be of the entire community. It is possible to group 20 of the individuals who appeared, representing 17 families, into a region north and east of the Lodgepole blowout. They would constitute about 7 per cent of the population. To determine how representative these witnesses were of the entire community population of 244 families, the Panel reviewed data from the WIN report. In this questionnaire study of the area residents comparing the frequency of symptoms experienced before, during, and after the blowout, the investigations showed a large increase in the number of people complaining of the previously discussed symptoms. This was not analysed statistically in the report and was used by the Panel only for the limited purpose of checking on how representative were the complaints of this small group of area residents who gave testimony. The residents came from Buck Creek, Cynthia, Drayton Valley, Easyford, Lodgepole, and Violet Grove areas.

7.2.2 Special Groups of Patients

Because of the lack of data, it was very difficult to assess the effect of the blowout on groups which might be expected to be at special risk, such as those with acute or chronic respiratory disease, individuals who are chronically ill, or small children. Two of the PASGEC witnesses, with previously diagnosed emphysema, said that they were considerably affected and the asthmatic husband of a third was described as incapacitated. The Panel accepts that such descriptions were probably accurate.

In the regions remote from the area of the blowout, even less health information was available. A retrospective chart review on 60 in-hospital patients and out-patients with chronic respiratory disease in Edmonton was performed by Dr. Neil Brown and colleagues. Because of inherent limitations in the design of the study, no firm conclusions can be drawn except to note that these patients had complaints during the period in question. Unfortunately, the time periods evaluated before and after the blowout were unequal and could not be fairly compared.

An important consideration is that although the H_2S was at very low levels in the Edmonton area (a maximum of 0.521 ppm), its odour was frequently evident. Since olfactory stimulation may cause a reflex contraction of smooth muscle in the tracheobronchial tree, it is possible that odour without irritation could have affected individuals in the Edmonton population who had increased airway reactivity from such diseases as asthma, chronic bronchitis, and emphysema. If this did occur, no permanent effect would be expected. Since 1477 complaints were made to Social Services and Community Health (SS&CH), 1187 from Edmonton residents, one can conclude that the odour was unpleasant for many healthy individuals as well.

7.2.3 Exposure to Low Levels of H_2S

Evidence was presented about Rotorua, New Zealand, a small community where residents are frequently exposed to H_2S from sulphurous hot springs in the area. Sporadically, the H_2S collects at levels which, on occasion, have even caused fatalities and this is understandable since the visitors from the Amoco medical team themselves recorded very high levels around holes or springs close to the ground. The Panel understands that the authorities do not monitor continuously for low level H_2S concentrations in Rotorua and have never conducted scientific health studies on the subject. Thus, the speculation that H_2S is well tolerated at low levels cannot be scientifically evaluated on the basis of their experience. A formal, well-conducted study including environmental monitoring might have been very useful and possibly could still be performed.

Dr. Smith, appearing for Amoco at the inquiry, argued that chronic low-level exposure to H_2S is not harmful based on the following two points. He drew an analogy between H_2S and the salts of cyanide, the latter of which has a low chronicity factor in animals. Cyanide, like H_2S, affects the enzyme cytochrome c-oxidase, thus disturbing critical electron transfer systems in the metabolism of cells. Secondly, he quoted from an abstract of recent experiments using mice and rats, which had been recently presented but not yet published. While these animals were exposed to 10, 30, and 80 ppm of H_2S for 90 days, lesions were seen only at 80 ppm. With the exception of the latter study, Dr. Smith's comments about H_2S were focused on systemic toxicological effects rather than the pathophysiological consequences to the respiratory system. Dr. Smith conceded that enzyme systems other than cytochrome c-oxidase were affected by H_2S.

In discussing these results, Dr. Clanachan of the University of Alberta noted that results drawn from experimentation with cyanide might not be analogous to H_2S, despite the fact that both of these affect cytochrome c-oxidase. He also pointed out that animals treated with injections of sodium sulphide might be differently affected by inhalation of H_2S because of the different ionization characteristics of sodium sulphide. Dr. Clanachan also cited experiments on goats exposed to 10 ppm of H_2S for 1 day which caused loss of appetite and reduced water intake.

7.2.4 Illness in Animals

The Panel decided to comment here on the problems of animal health because of the many similarities in signs, particularly related to respiratory problems, common to both people and animals resident in the Lodgepole area during the blowout.

Many of the 30 local area residents referred to problems with their farm animals during the blowout period. They noted these animals suffered from runny eyes and noses, coughing, and decreased food intake. There were striking descriptions of most of the members of the cattle herds being affected, the young animals more than the older ones. Residents also testified that animals suffered diarrhea, red stools, red urine, and decreased weight gain. Members of five families mentioned the almost total disappearance of birds or small animals which did not reappear for a long time after the blowout was controlled.

Dr. Josephson, a veterinarian in private practice in the area, described the animals as commonly having respiratory and ocular irritation and decreased food intake. She stated that their temperatures were normal despite the signs. In animals with pre-existing respiratory trouble, there were unsatisfactory and unusual responses to antibiotic treatment during the time when the well was blowing but improvement during the period of flaring.

The Panel accepts that the high rate of ocular and respiratory symptoms reflecting mucous membrane irritation in different species of animals simultaneously and the disappearance of birds and small animals was unique and cannot be explained on the basis of natural causes. It is much more difficult to interpret the descriptions of gastrointestinal illnesses in animals since these are known to occur in the absence of atmospheric pollution.

Representatives of Alberta Agriculture (AA) testified that they perceived their role in such incidents as the Lodgepole blowout as that of responding to requests for assistance from the farm community.

Representatives of AA did not visit the Drayton Valley area until 2 December when they went to three farms over a 1-day period, 1 week after the well was accidently ignited the second time. No epidemiological studies were performed. The local District Agriculturist said he contacted local veterinarians who did not report unusual livestock problems. It is noteworthy that many people, with domestic animals which suffered illnesses, stated that they had not communicated with AA, but either relied on local veterinarians or did not complain at all.

The claim that air pollutants caused spontaneous abortions in livestock and other animals was made by several farm witnesses. AA presented a review showing no increase in the rate of spontaneous abortions in west central Alberta compared to elsewhere in the province or to previous years. This disparity in opinion about abortions may be partly due to a failure of communication and inadequate submission of specimens. Unfortunately, this very important question cannot be resolved one way or the other on the basis of information now available.

In another matter related to livestock, staff of the Alberta Environmental Centre attempted to determine the effects of the emissions on certain important enzymes of cattle. Blood samples were taken from cattle from ten herds in the affected area during the blowout and subsequent to the capping of the well, as well as from two control herds in the Vegreville area.

These studies showed that some statistically significant biochemical perturbations did occur in animals within the exposure area. In all cases, however, the changes appeared to be transient and reversible. The investigators advised that these results are highly experimental in nature and must be interpreted with considerable caution, particularly when assessing suspected clinical disease in the animals. At present, the importance of these results is not known.

7.2.5 Differential Diagnostic Possibilities of Human Illness

There are two alternative differential diagnostic possibilities, other than a physical illness due to the emissions, to explain the illnesses of the 30 residents who presented evidence. These are either an acute infectious disease process which occurred at the same time as the blowout, or a psychological illness provoked by the stress of the situation. There is considerable evidence against these possibilities. It would be unusual for an infectious process to start simultaneously among a population so widely separated. As well, there was an absence of certain systemic symptoms so characteristic of most epidemics. The symptoms generally abated when the residents left the area and recurred rapidly when they returned during the blowout period. There was no evidence that an epidemic-type infection was identified by physicians local to the Drayton Valley area during the period.

A mass psychological illness is unlikely for a number of reasons, including the fact that such episodes have not been reported among stable farm families consisting of mature adults and very small children. The physical symptoms among the area residents were made up in large part of complaints which can be best described as irritation of exposed mucous membranes. Similar signs were noted in animals and there was an acknowledged disappearance of wildlife, including birds and small mammals. Air monitoring revealed levels of H_2S as high as 15 ppm for very short periods at residences inthe Lodgepole region. Recordings varied up to a peak of 30 ppm on one occasion and beyond 30 ppm on four occasions away from residences. Section 7.4.2 gives further details respecting monitoring results in the region.

In contrast, during an epidemic illness said to be of psychological origin which occurred in adolescent school girls in the Middle East, environmental levels of H_2S were of the order of 0.05 ppm. In a telephone survey, conducted without controls, of residents in Edmonton, Drayton Valley, and the Lodgepole region, Jarvis has suggested that "social contagion" explained the symptoms of residents in all areas. With respect to Lodgepole area residents, his interpretation seems to be that the illness seen in animals was due to a distortion of reality in the eyes of the observers. He thus applied the term "social contagion" to the population at a time when medical and environmental data was not available to him. It is noteworthy that the term was also used by Dr. Milby, who appeared as an expert witness on behalf of Amoco. He repeated the Jarvis explanation without a critical evaluation of the data on which it was based, including the lack of controls in that study.

7.2.6 Available Medical Literature

There was almost a total absence of information on the effects on humans of low level extended exposures to H_2S. Information is available describing the acute effects of high level accidental exposure in humans.

7.3 The Standards Adopted to Protect Human Health from Emissions from the Blowout

To protect the health of persons exposed to emissions from the well, it was necessary to determine the threshold concentration of the contaminants that could be safely accepted by exposed persons. At the time of the blowout, the concerns were related mainly to H_2S; however, during the course of the inquiry, reference was made to other possible contaminants. While the well was on fire, the H_2S was converted to SO_2 and its standards became applicable. The primary focus during the inquiry, however, was on H_2S emissions and the standards applied.

7.3.1 The H_2S Standards Applied During the Blowout and Their Basis

Several of the participants provided evidence respecting the H_2S standards applied during the blowout period. Amoco indicated that it had been advised by the ERCB that the following standards were in effect:

(a) if concentrations exceeded 5 ppm for 6 hours or 10 ppm for 1 hour
  - suggest residents evacuate the area,

(b) if concentrations reached 15 ppm with an increasing trend
  - advise all residents to leave the area, and

(c) if concentrations exceeded 20 ppm
  - evacuation would be considered mandatory.

The evidence of AE and the ERCB staff generally confirmed Amoco's statements but there were some differences. For example, there appeared to be different interpretations about whether the mandatory evacuation limit of 20 ppm was in effect by 18 October or actually was adopted sometime later. Similarly, there was reference to an evacuation limit when concentrations exceeded 10 ppm for 8 hours. SS&CH stated that, at a meeting on 25 November, the PBOH agreed with the following action levels as presented by AE:

> "...healthy normal adults should be advised to evacuate an area where hydrogen sulphide levels exceeded 10 parts per million for eight hours. This level is the same as the eight-hour occupational exposure limit used in the Province of Alberta ..."
>
> "A concentration of 20 parts per million for any period was established as the level at which persons must evacuate."
>
> "... for persons believed to be more sensitive, ... the very young, the very old, and those with respiratory disorders. Evacuation was recommended for such persons when average levels exceed five parts per million for six hours or 10 parts per million for one hour in the presence of persistence or worsening of symptoms ...".

Reference also was made to the ERCB inquiry in 1978 which was held to consider the blowout of the 7-10 well in the same area. The report, Inquiry Report 78-8, indicates that the evacuation standard established for that occasion was that "... mass evacuation should not take place unless the H_2S readings exceeded 10 ppm for an extended period of time (five to six hours). Evacuation of sensitive individuals might be advisable at lower levels (5 ppm) ..." and that "Through consultation with medical experts from the Occupational Health and Safety Division, Alberta Labour, it was decided that persistent levels of 3 to 5 ppm hydrogen sulphide should require evacuation of residents very sensitive to hydrogen sulphide. At levels of 15 ppm persisting for longer than 15 minutes, all individuals should be evacuated."

The Panel concludes, on the basis of the somewhat confusing evidence, that the following evacuation criteria were in effect for most of the blowout period:

(a) suggest residents consider evacuation if concentrations become 5 ppm for 6 hours or 10 ppm for 1 hour,

(b) advise residents to evacuate if concentrations become 10 ppm for 8 hours,

(c) urge evacuation at 15 ppm, and

(d) require evacuation at 20 ppm.

The evidence suggests to the Panel that while reference was made to special standards for more sensitive people, that need was not specifically recognized in the standards except perhaps for the case of 5 ppm for 6 hours. In addition, there was no effort made to implement measures to determine who in the population was sensitive, and measures to protect these people, with the exception that Amoco was prepared to cover costs of relocation for persons who complained and wanted to leave the area.

At its meeting in January 1983, the PBOH decided to issue a booklet to inform residents of health information on H_2S which could be used for any future incident. The booklet was made public as an exhibit at the inquiry in January 1984. The following guidelines or standards for evacuation are included in the booklet:

> "If **average** H_2S levels exceed 5 ppm for 6 hours or 10 ppm for 1 hour or more and symptoms persist or become more severe, individuals should consider moving from the area until the levels are reduced.
>
> If **average** levels exceed 10 ppm for 8 hours or more, local conditions in the area will be assessed and you may be advised to leave the area until the levels are reduced.
>
> If environmental monitoring indicates that a level of 20 ppm or more will be reached and conditions indicate that a serious health hazard exists, mandatory evacuation will be carried out under the direction of your local municipality.
>
> Sensitive individuals such as children, the elderly or those with pre-existing disease conditions (asthma, emphysema, etc.) should consider leaving the area if symptoms persist. Medical advice should be obtained if possible."

The rationale for the exposure limits adopted by the PBOH was described by reference to the occupational exposure limit of 10 ppm for 8 hours. The limit was described as being "... consistent with many such exposure levels in other parts of the world ...". Relating the exposure to health effects, Dr. Orford testified that "Below 140 parts per million, irritant effects are not generally fatal but may lead to irreversible tissue damage. At 20 parts per million or above, conjunctivitis, which is eye inflamation, occurs in many people and in some cases, could be irreversible if exposure continues over a long period of time. At 10 parts per million or less, effects are short-term and reversible if they occur at all. This is the reason why most jurisdictions have adopted 10 parts per million as the eight-hour occupational exposure limit".

PASGEC was very critical about the evacuation standards contending that they were inappropriate. It was especially concerned about the more sensitive residents who could be at risk from the H_2S concentrations. Several of the witnesses referred to this matter and described how actual concentrations affected them or their family.

The evidence indicates a degree of confusion or uncertainty with respect to the evacuation limits that were in effect during the blowout period. The most common standard appears to have been 5 ppm for 6 hours or 10 ppm for 1 hour, which was used for suggesting evacuation. Advice to leave immediately was triggered at 15 ppm and mandatory evacuation would have taken place at 20 ppm. While reference was made to lower rates applying to more sensitive people, except for Amoco, there was no indication that these rates were applied during the blowout period.

The Panel believes that there was a deficiency in the standards during the event with respect to sensitive people. The current standards issued by the PBOH make reference to the more sensitive individuals but they do not provide any specific guidelines except to recommend evacuation "... if symptoms persist" and to obtain medical advice. The Panel believes that further consideration should be given to identifying appropriate action for sensitive individuals exposed to H_2S. The results of the monitoring data described in the following section may provide a basis for that reconsideration. The Panel recognizes that the problem is difficult but believes it should be addressed.

7.4 Monitoring H_2S Emissions from the Well

The emissions from the 13-12 well, while it was out of control and not on fire, posed a potentially serious threat to people living or working in the area. Only a few families resided in the immediate area and the nearest communities were some 20 km distant. Because of the potential dangers, it was imperative that an effective monitoring program for H_2S be implemented quickly. The following sections describe and comment on the monitoring program, the monitoring results, and the effectiveness of the program.

7.4.1 The Monitoring Plan

At midnight on 17 October 1982, the first AE mobile air monitor commenced monitoring in the Lodgepole area. Amoco had two monitors in the area which did spot checks during the night. The ERCB monitor arrived at noon on 18 October and before the end of the day four mobile air monitors were continuously monitoring in the area. A fifth unit, AE's mobile laboratory, was in the area on 23 October. Additionally, two stationary monitors were established at the nearby community of Lodgepole and at Drayton Valley which is some 45 km from the well. Later, stationary monitors were established in Cynthia and at the Brazeau Dam site on 23 and 28 October, respectively. The location of the stationary monitors and the area generally surveyed by the mobile monitors is shown in Figure 7.2.

The rationale for the monitoring program was to maintain a check on the H_2S concentrations in each of the population centres through the stationary monitors and to use the mobile monitors to check on concentrations in the rural areas, particularly near residences or occupied areas. The mobile monitors attempted to define the highest H_2S concentrations with the objective of being able to identify the most serious situations. The monitoring was conducted on a 24-hour basis and was co-ordinated by AE. Monitoring results from both the stationary and mobile units were used to identify the high concentration areas. Evidence submitted at the inquiry indicated that where high concentrations were identified, mobile monitors would converge on the area to ensure that monitoring was sufficient to identify any potential danger. The general plan was premised on either the evacuation of people where the monitoring indicated that the evacuation standards would be exceeded or the ignition of the well when evacuation was not practical, such as in Drayton Valley.

Participants at the inquiry identified several criticisms of the monitoring program. Probably the major complaint was the lack of information provided to residents about either the plan or the H_2S concentrations recorded by the monitors. For example, several local residents testified that they had called either the ERCB or Amoco to advise that concentrations appeared to be very high in the area and had requested that the situation be investigated. A monitoring unit was promised but the caller did not receive confirmation of either its arrival or the results. Consequently, many believed that the requests had not been checked. In contrast, the evidence provided by the monitoring representatives indicated that the calls were always responded to, but as long as the situation was not serious, monitoring personnel did not always consult with the local residents.

Other criticisms related to whether there were enough monitoring units to satisfactorily cover the entire area potentially affected and whether the recording instruments were adequate for the concentrations being encountered. With respect to the five mobile monitors, the evidence indicated that automatic recording devices were in four of the monitors with limits of 10, 10, 5, and 1 ppm H_2S, respectively. The other monitor was capable of monitoring up to 30 ppm but it did not have an automatic recording device. In three units, the automatic recording instruments were supplemented by Drager units which could be used to detect approximate concentrations up to 60 ppm, and two units had Dictaphone instruments which could read up to 100 ppm. The stationary units at Cynthia, Lodgepole, Drayton Valley, and Brazeau Dam had recording capacities of 3.27, 5, 5, and 1 ppm, respectively.

Participants questioned whether unmanned stationary units were adequate and some suggested Drager instruments and crush ampoules should have been provided to residents, especially in more remote areas and in the Pembina River Valley. The Panel believes the suggestion of supplying Drager instruments and possibly crush ampoules to residents in remote rural areas should be considered, along with instruction in their use, as part of an overall monitoring program.

In the Panel's view, the design of the monitoring program was generally appropriate. The Panel agrees with the decision to use a combination of stationary and mobile monitors with the latter roving the area to identify high concentrations and ensure the protection of isolated residents. The evidence on the monitoring results, which is discussed in section 7.4.2, indicates that the monitoring units engaged in the program were generally sufficient to effectively carry out the responsibilities, however, one or two additional units would have been advantageous to allow for possible emergencies and occasions when the monitoring units were inoperative. Additionally, it would have been preferable to employ units capable of measuring higher concentrations of H_2S but the Panel recognizes that such units were not readily available. Having regard for the fact that there was no preplanning for monitoring in the event of a blowout, the Panel believes that the plan was as complete and extensive as could be expected. The Panel agrees that such a general plan should be established and AE should co-ordinate it in any future event.

The major deficiency in the monitoring plan related to communications. With the advantage of hindsight, it is clear that special efforts should have been made to provide local residents with information about the monitoring plan as well as the detailed results of it, including specific readings. Additionally, the program would have been enhanced and may have resulted in better communication to the press and the public if a central dispatcher had been in charge of the program. By appropriate advance planning, particularly by AE and the ERCB, some of the problems encountered in the Lodgepole case could be avoided and a more credible system could be implemented for any future incidents.

7.4.2 Monitoring Results

7.4.2.1 H_2S Concentrations Over the Broad Area

Amoco presented the results of the mobile and stationary monitors by isopleths of average hourly concentrations for each day that the well was out of control and not ignited. It contended that these data provided a fair representation of the concentrations in the area. The data were subject to extensive examination at the inquiry and there was considerable controversy about their interpretation and validity. Some participants alleged that actual peak recordings during the Cynthia episode on 23 and 24 November, when concentrations in the Cynthia area were high and evacuation was being considered, were substantially higher than indicated by the average hourly data.

AE filed the operator's notes from its mobile monitoring units and half-hourly and hourly averages for the stationary monitors. Various attempts were made through examination to compare the AE data with the results presented by Amoco.

One of the interpretational problems related to the method of calculating average hourly concentrations when the readings for the mobile monitors were "off scale". Amoco indicated that under those circumstances, providing the concentration continued for more than 1 minute, the instrument's maximum reading was assumed to apply for the full hour. For its stationary units, AE averaged the readings over the hour and added a greater-than sign to the reading. Further details respecting the determination of hourly average concentrations are provided in Appendix 7.

The extreme variability of the mobile monitoring data also resulted in interpretational difficulties and questions about the data. Amoco contended that extreme variations in concentrations were to be expected because the plume was almost constantly moving due to atmospheric conditions and consequently there were extreme gradients between the outer edge of the plume and its centre. Some participants questioned whether the data were reliable and whether the monitoring plan was actually followed. Others suggested that the variability indicated the difficulties of attempting to construct isopleths on the basis of mobile monitoring data.

The Panel has reviewed the data filed in evidence. It does not believe that the hourly average contours calculated on the basis of mobile monitoring data are a valid representation of the actual concentrations. In its view, there is insufficient data to derive meaningful average hourly concentrations because the mobile monitors were virtually always on the move and the concentrations were obviously variable depending on the path of the plume. The mobile monitoring was designed to identify the location of the highest concentrations in areas where there were residents and no stationary monitors. It was not designed to provide a base for calculating hourly average concentrations over the area. A further complication was the fact that in the high concentration areas, the readings from the automatic recording devices for both stationary and mobile monitors were sometimes off scale and actual concentrations were determined by the Dictaphone and Drager units. The fact that the average hourly concentrations depicted in the figures presented by Amoco could not be used does not, in the Panel's view, detract from the effectiveness of the monitoring program itself. It simply means that there is insufficient data to determine average concentrations over the broad area.

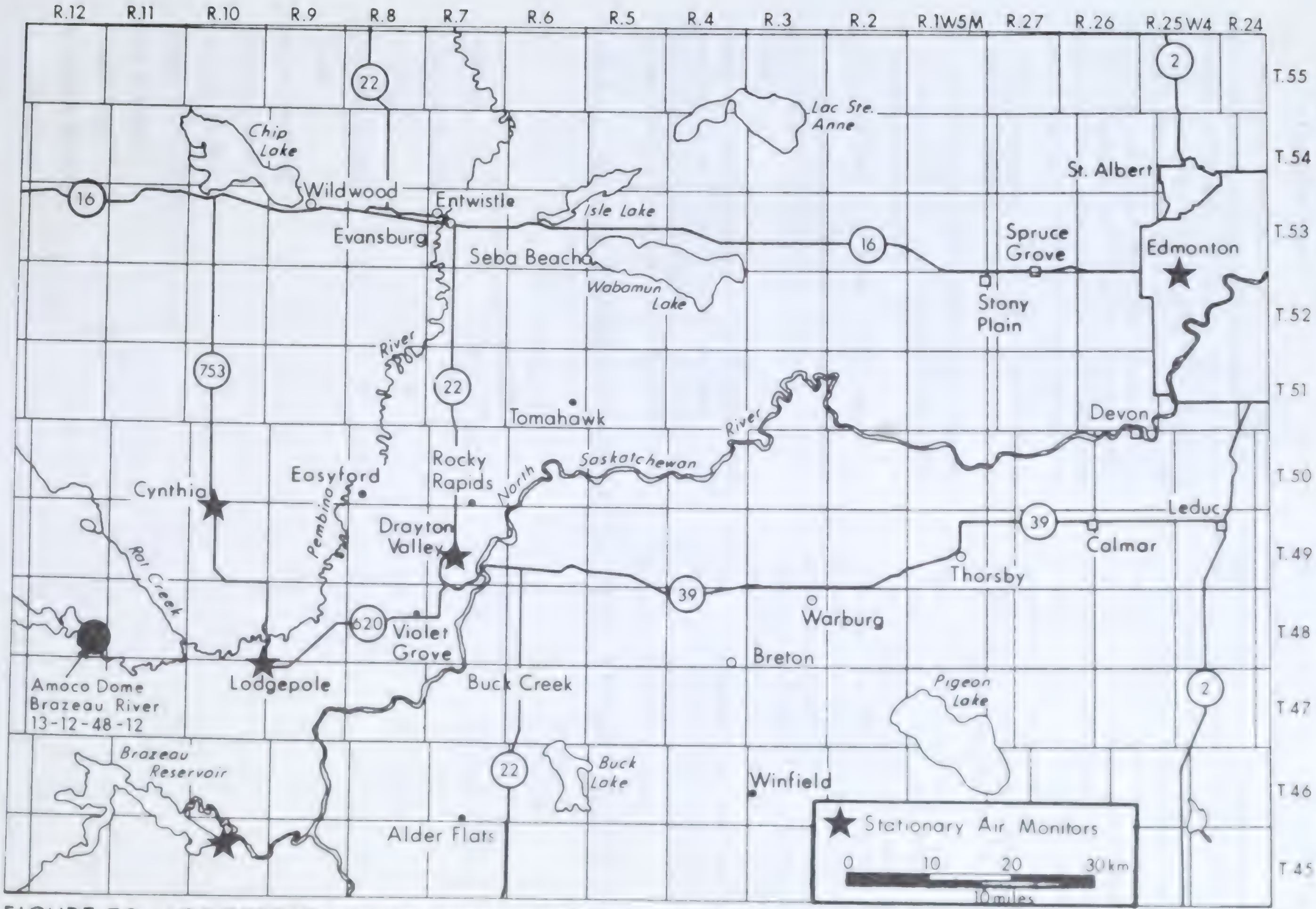


FIGURE 7.2 LODGEPOLE - EDMONTON AREA SHOWING LOCATION OF STATIONARY AIR MONITORS

7.4.2.2 H_2S Concentrations at Populated or Occupied Areas

The Panel appreciates that local residents were seriously concerned about the H_2S concentrations particularly having regard for the limited information they received and the potential risks involved. In view of the controversy regarding the interpretation of the monitoring data, the Panel has summarized the monitoring results at residences for both stationary and mobile units by geographical location where concentrations greater than 5 and 10 ppm were recorded. The 5-ppm cut-off was selected because it was

(a) the upper suggested limit of the evacuation range for sensitive people,

(b) substantially less than the standards applied to workers on site and less than the evacuation criteria applied during the incident, and

(c) the upper limit of one of the mobile monitors.

The 10-ppm level was selected in order to identify the most serious levels and to relate them to the general evacuation standards.

Figure 7.2 shows the general area affected by H_2S emissions from the well. Two of the communities, Cynthia and Lodgepole, are approximately 20 km from the well, Drayton Valley is some 45 km, and Edmonton approximately 130 km distant. The area nearest the well is sparsely populated with a few ranches and farms as well as lumber and oil and gas operations.

Figure 7.3 shows in greater detail the area nearest the well including the prohibited entry area prescribed by ERCB Order FH 82-1. Residences and industrial operations where readings greater than 5 ppm were obtained are identified. Most of these were located within a 20-km radius of the well. The H_2S concentrations at those locations were monitored by the mobile units particularly when the concentrations were relatively high. H_2S levels in the communities of Cynthia, Lodgepole, and Drayton Valley were recorded on stationary monitors which were supplemented by mobile units when the former were off scale.

Figure 7.3 also shows the number of hours that monitors reported concentrations greater than 5 and 10 ppm. A review of the monitoring records indicates that all of the concentrations greater than 10 ppm were within approximately a 20-km radius. There were locations outside that area that experienced H_2S concentrations in excess of 5 ppm but not at residences or populated centres except for two instances at the hamlet of Violet Grove.

Table 7.1 provides additional detail respecting the recordings at each of the locations identified in Figure 7.3. In each case, the maximum concentration reported during the hour is shown in the table.

TABLE 7.1 H_2S CONCENTRATIONS GREATER THAN 10 AND 5 PPM RECORDED AT RESIDENCES

Location	Number of Hours H_2S Conc > 10 ppm	Number of Incidents	Number of Hours H_2S Conc > 5 ppm and ≤ 10 ppm	Number of Incidents
Centennial Lumber	9	3	18	8
Lodgepole	3	3	20	8
Chevron Gas Plant	6	3	3	3
Cynthia	2	1	6	1
Sargent Residence	4	2	2	1
Petro-Can Battery	3	2	1	1
Tall Pine Timber	1	1	3	3
Emperingham Residence	1	1	1	1
Nail Residence	1	1	1	1
Violet Grove	0	0	2	2
Proudlove Residence	1	1	0	0
Negraiff Lumber	0	0	2	2
Fell Residence	0	0	1	1
Texaco Battery	0	0	1	1

Table 7.1 shows that people living and working at Centennial Lumber were exposed to the highest H_2S concentrations recorded. For some 18 hours during the 26 days that the blowout was not ignited, the H_2S concentrations were greater than 5 ppm and for 9 hours they were in excess of 10 ppm. On one occasion, the concentrations reached 15 ppm and the people were evacuated. The maximum concentration reported was 23 ppm but that occurred after evacuation of the residents. A PASGEC witness stated she had been advised that the level reached 35 ppm on that occasion.

Lodgepole had 23 hours of H_2S concentrations in excess of 5 ppm and 3 hours in excess of 10 ppm, while Cynthia had 8 hours greater than 5 ppm and 2 hours in excess of 10 ppm. The maximum concentrations in each community were 14.5 and 14.0 ppm, respectively.

With respect to Cynthia, the Panel decided to provide details of the monitoring results for 23 and 24 November because of the controversy respecting the need for evacuation during that incident. Figure 7.4 shows the hourly concentrations over the episode on 23 and 24 November. In compiling Figure 7.4, the Panel has shown as an hourly reading the hourly averages presented by Amoco until the stationary monitor went off scale at 16:00. After that, the readings were obtained by mobile monitors and some are the maximum readings recorded during the hour, regardless of the duration, and others are hourly averages. Unfortunately, limited data is available for the hours 03:00 to 16:00 on 24 November because the stationary monitor was inoperative and the mobile monitors were called away at 03:00 to monitor in the area northwest of Lodgepole which resulted in the voluntary evacuation of the Sargent family at 06:05.

The Cynthia data shows that the hourly concentrations reached a peak of 14 ppm between 17:00 and 18:00 on 23 November and subsequently declined to less than 4 ppm by 03:00 and to 1 ppm at 06:00 on 24 November. Up to 03:00 on 24 November, the stationary monitor was supplemented by the three mobile monitors. The Panel is satisfied that the data shown on Figure 7.4 are reliable because the AE mobile monitor with an instrument range of 30 ppm, and the Amoco mobile unit, with a range of 10 ppm, were at or near Cynthia from 12:45 to 19:45 on 23 November and 16:00 on 23 November to 03:00 on 24 November, respectively.

Table 7.2 summarizes the data from the stationary monitors located in Cynthia, Lodgepole, Drayton Valley, Edmonton, and Calgary. For Cynthia and Lodgepole, the two communities located nearest the well, the H_2S concentrations exceeded 5 ppm for 8 and 23 hours, respectively, and were in excess of 1 ppm for about 5 and 13 per cent of the total monitored hours, respectively. Concentrations less than 0.1 ppm were recorded for 80 and 70 per cent of the time, respectively. For Drayton Valley, the concentrations did not exceed 5 ppm, exceeded 1 ppm about 4 per cent and were less than 0.1 ppm about 80 per cent of the time. In Edmonton, the maximum concentration was 0.52 ppm, and the maximum hourly average was 0.47 ppm and for about 93 per cent of the time was less than 0.1 ppm. For Calgary, the maximum concentration was 0.328 ppm,

TABLE 7.2 H_2S CONCENTRATIONS RECORDED IN POPULATED CENTRES BY STATIONARY MONITORS

H_2S Conc (ppm)	Cynthia		Lodgepole		Drayton Valley		Edmonton(1)		Calgary(1)	
	Hours	%	Hours	%	Hours	%	Hours	%	Hours	%
> 5	8(2)	1.5	23(2)	3.7	0	0	0	0	0	0
3 to 5	6(2)	1.2	12	1.9	4	0.7	0	0	0	0
1 to 3	10	1.9	47	7.6	18	3.1	0	0	0	0
0.5 to 1	19	3.7	24	3.9	20	3.4	0	0	0	0
0.1 to 0.5	67	13.0	84	13.5	74	12.6	37	6.87	9	2.9
< 0.1	407	78.7	430	69.4	470	80.2	497	93.1	289	97.2
Total	517	100	619	100	586	100	533	100	297	100

(1) The statistics presented for Calgary and Edmonton are averages of the readings recorded at the two stationary air monitors in each city.

(2) These numbers include readings from mobile monitors where the stationary capacity was exceeded.

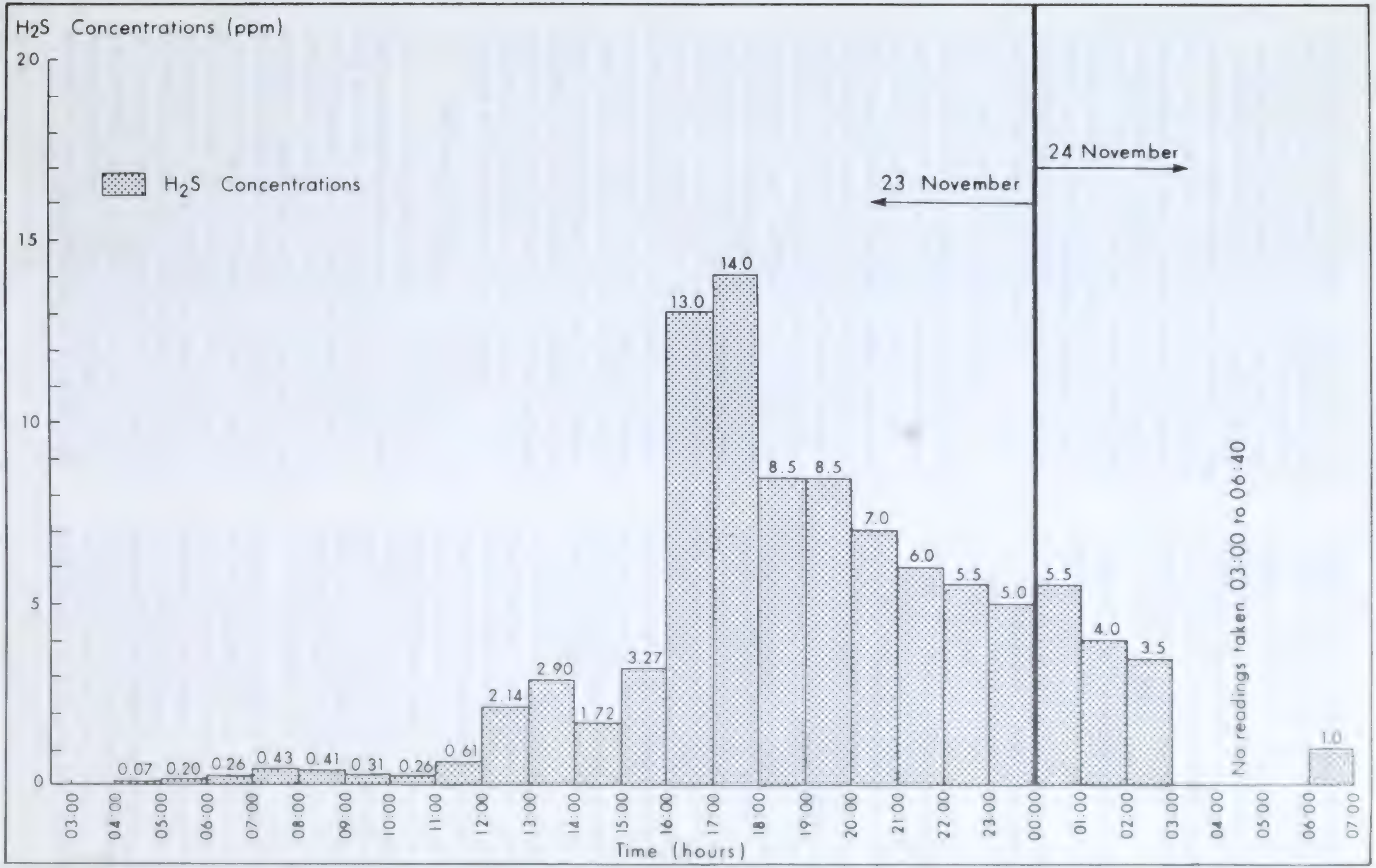


FIGURE 7.4 HOURLY MAXIMUM H_2S CONCENTRATIONS IN CYNTHIA. 23-24 November 1982.

and the maximum hourly average was 0.33 ppm and was less than 0.1 ppm for about 97 per cent of the time. A more detailed review of the Calgary and Edmonton data indicates that about 12 per cent and 22 per cent, respectively, of the total monitored hours were in excess of 0.01 ppm, which is the generally accepted odour threshold for H_2S for most people. Similar analysis is not possible for the three communities near the blowout because the monitoring equipment was not sufficiently sensitive, but based on Table 7.2, the Panel believes the percentages would have been significantly greater and probably in the order of 40 to 50 per cent. The Panel presents this data because it might have significance in considering appropriate standards and action for the more sensitive people.

7.4.3 Effectiveness of the Monitoring

In the Panel's view, the monitoring program allowed for rapid detection of serious H_2S concentrations and thereby permitted warning and protection of residents in the area. The location of stationary monitors in settled communities was sound and the use of mobile monitors for the scattered residents was practical. The major deficiencies related to communicating with the public the details of the monitoring plan and its results. Additionally, the lack of adequate back-up strength became apparent on 24 November when the Cynthia monitor became inoperative and the mobile monitors were required to cover an area of more serious concern. The Cynthia incident was further complicated by the limited recording range of the stationary monitor and the fact that it was not manned except for the first two weeks. With respect to the monitoring instruments, it would have been much more satisfactory if the stationary monitors had been continuously supervised, had the recording capacity of stationary and mobile monitors been not less than the mandatory evacuation standard, and each equipped with continuous recording devices.

7.5 Adequacy of Emergency Response Plan

Several participants contended that a site-specific emergency response plan is necessary in order to deal effectively with a blowout. Particular reference was made to the identification, location, and other details of persons who might be affected by a blowout. The Amoco response plan was a general plan rather than site-specific and engendered considerable discussion. The Panel agrees that a site-specific emergency response plan should be part of the requirement for a critical sour well and that concept has been included in the ERCB's Draft Interim Directive for critical sour wells. After reviewing the Amoco plan, the Panel can also see considerable merit in having available to all parties a general response plan that provides information that would help in responding to any blowout. The Panel recognizes that such a plan has been prepared and will be reviewed after this report has been issued. The plan is referred to further in section 9.5.

Reference was made at the inquiry to the use of the 100-ppm H_2S isopleth in the ERCB's Interim Directive ID-OG-76-2 as the basis for emergency sour gas procedures. PASGEC contended that it would be much more appropriate to use a 15-ppm isopleth since that represented the evacuation criteria.

It appears to the Panel that PASGEC's recommendation inherently assumes that:

(a) the purpose of the emergency response plan is to provide specific plans for every case where a person might need to leave an area because of a sour gas release, and

(b) the H_2S concentrations predicted by the isopleth model are reasonably representative of those that would prevail during a sour gas release.

The Panel questions whether the first assumption is practical or in the best interest of the public. A sour gas release can result in a variety of situations. If the release is near a major population centre, then immediate ignition would likely be the required action because evacuation would not be practical. If the release is near a less populated area, then the evacuation of those people in immediate danger would probably be required. Persons residing farther from the release, while not in immediate danger, might need to be evacuated under certain special circumstances. An effective monitoring system is required in order to identify those special cases.

As the Panel sees it, the site-specific emergency response plan should spell out the immediate action that would be required in the event of an emergency. It would identify those residents in immediate danger from the release and specify the actions to be taken. The general emergency plan would address broader issues, such as implementing suitable monitoring programs, communication with the public, and advising residents that might require evacuation. The Panel recommends that the ERCB and Government departments give further consideration to these matters after obtaining the views of industry and the public.

The assumption that the isopleth model provides concentrations comparable to those that could be expected from a sour gas release can be tested by comparing actual and predicted H_2S concentrations during the 26 days the 13-12 well was not on fire. Figure 7.5 shows the 15-ppm isopleth. Because of the uncertainty respecting the actual flow rate from the well, and since current evidence suggests the flow was likely greater than 1.4×10^6 m^3 per day, the Panel has calculated the 15-ppm isopleth on the basis of flow rates of 1.4×10^6 m^3 per day and 2.1×10^6 m^3 per day. The shaded area shown in Figure 7.5, therefore, represents the probable bounds of the 15-ppm isopleth.

Good monitoring data is available with respect to the outer limit of the 15-ppm band. Drayton Valley, which is just beyond the outer circumference, did not have any concentrations greater than 5 ppm. Mobile monitoring recorded two occasions when the concentrations at Violet Grove were in excess of 5 ppm. The mobile monitoring did not record any other cases of concentrations greater than 5 ppm at residences located within the band. The stationary monitor at Drayton Valley recorded only 4 hours or 0.7 per cent of the total monitored hours when the concentrations were between 3 and 5 ppm. Cynthia and Lodgepole are located to the west of the 15-ppm isopleth band and would therefore be expected to have higher isopleth calculations. The Lodgepole monitor recorded 3 hours when the concentrations were greater than 10 ppm and 20 hours when they were greater than 5 ppm but less than 10 ppm. In the case of Cynthia, there were 2 hours when the concentrations exceeded 10 ppm and 6 hours when they were greater than 5 ppm but less than 10 ppm. On an overall basis, H_2S concentrations at Cynthia were greater than 5 ppm for 1.5 per cent of the recorded hours and 3.7 per cent in the case of Lodgepole. As indicated previously, all of the concentrations greater than 10 ppm recorded by mobile monitors at residences were within the 20-km radius of the well and to the west of the 15-ppm band.

On the basis of the foregoing comparison, the Panel concludes that the isopleth calculation results in predicted values that are about three times greater than those actually measured during the 26 days, even for those special instances when extreme meteorological conditions prevailed. The data suggests that for 95 per cent of the time or more, the difference between predicted and measured would be several times greater than the factor of 3.

Notwithstanding the foregoing comments, the Panel agrees that further consideration be given by the ERCB and other parties to the appropriateness of using the 100-ppm isopleth for determining the area that should be included in the site-specific emergency response plan.

7.6 Evacuation of Residents Due to H_2S Concentrations

Amoco's evidence at the hearing indicated that it was prepared to cover the cost of persons who wished to move out of the affected area. Some 28 persons plus 4 families changed domicile for varying periods under this arrangement. In addition to these voluntary transfers, the evidence indicated six instances during the period when residents evacuated because H_2S concentrations were increasing towards 15 ppm. These are summarized below:

29 October 1982	– Empiringham Residence
20 November 1982	– Centennial Lumber
17 and 20 November 1982	– Tall Pine Timber
21 and 24 November 1982	– Sargent Residence

A few of the oil industry operations were also evacuated because of concentrations reaching the evacuation limit.

Evacuation of Cynthia was under active consideration on 23 November. H_2S concentrations increased from about 2 ppm at 12:00 to 13 ppm by 16:00 (Figure 7.4). By 17:00, the concentration had increased to 14 ppm and between 17:30 and 17:50, residents were notified of the high readings and advised that evacuation might be necessary. The concentrations then began to decline and by 18:00 were 8.5 ppm. The inquiry record indicates that notification of residents was discontinued at 18:15. By 24:00, the concentration had declined to 5 ppm.

The Panel has compared the monitoring results with the H_2S evacuation standards outlined in section 7.3.1 to determine whether those standards were actually applied. It will be recalled that the following standards were used:

(a) in excess of 5 ppm for 6 hours or 10 ppm for 1 hour – suggest residents consider leaving the area,

(b) in excess of 10 ppm for 8 hours – advise residents to leave,

(c) in excess of 15 ppm – urge residents to leave, and

(d) at 20 ppm – require evacuation.

For the areas protected by the mobile monitors, the only really effective standards were those for urging or requiring that evacuation take place when H_2S concentrations were found to be 15 ppm and 20 ppm, respectively, since the other standards required continuous monitoring data. The Panel's review of the monitoring data indicates only a few instances of 15 ppm concentrations at residences or populated areas, and in each case, the records show that the people left the area upon being advised to do so.

With respect to the three communities where stationary monitors were installed and supplemented as necessary by mobile monitors, each of the evacuation criteria could be applied. There were no incidents at Lodgepole or Drayton Valley where H_2S concentrations exceeded 5 ppm for 6 hours, 10 ppm for 8 hours, or 15 ppm for any period of time. With respect to Cynthia, concentrations exceeded 5 ppm for 7 hours but, as indicated in Figure 7.3, the peak level of 14 ppm occurred during the second hour of readings greater than 5 ppm and thereafter declined to 5.5 ppm by the seventh hour. Subsequently, the concentrations declined to less than 5 ppm. There were 2 hours when the concentration exceeded 10 ppm and the maximum level did not rise to 15 ppm. The evidence shows that Cynthia residents were advised of the possible need to evacuate although some of them may have been missed. When concentrations decreased, the program was cancelled, but it appears that this was also not fully communicated.

The Panel is satisfied that the evacuation standards were applied in Cynthia on 23 November but believes that communication was not adequate under those trying circumstances. The Panel believes that if Cynthia residents had been advised of evacuation procedures in the early stages of the blowout to prepare them for that eventuality, then some of the concerns and negative reactions would have been avoided. Additionally, if the complete information necessary to inform all residents had been compiled in advance, then the notification of residents of any necessary evacuation could have been carried out more effectively. A similar situation could have occurred at Lodgepole. The Panel believes that the emergency response plan should include provisions for informing residents of evacuation possibilities and procedures.

7.7 SO_2 and Other Emissions

While the focus of discussion at the inquiry related to H_2S emissions, reference was also made to SO_2 emissions, as well as to other emissions, during the time the well was on fire. Evidence indicated that the evacuation limits for SO_2 were 0.3 ppm for 24 hours and 1.0 ppm for 3 hours.

The Panel has compared the SO_2 monitoring data with the evacuation limits. With respect to the three communities in which stationary monitors were installed, the peak hourly concentration of 0.075 ppm occurred on 4 December at Drayton Valley. About 98 per cent of the time, the readings at the stationary monitors were less than 0.01 ppm. The maximum peak reading on the mobile monitors was 0.275 ppm which occurred on Highway 16 between the Devon overpass and Edson on 4 November. These results indicate that the SO_2 concentrations that occurred during the blowout were substantially less than the evacuation limits.

With respect to emissions of other components from the blowout well the Panel is not able to make any assessment because there is no data available. It understands that the ERCB has obtained samples of the well effluent and is having them analysed. Those results may provide useful information and should be made public. In addition, AE recommended that the ERCB determine the gaseous composition of various oil and gas fields in Alberta and the Panel agrees with the recommendation.

7.8 Summary of Panel's Views

Many individuals living in the Lodgepole region suffered from headache, respiratory, and gastrointestinal symptoms during the blowout. These people were exposed to H_2S during this time and it is probable that their symptoms were caused by this exposure.

Domestic animals in the Lodgepole region were similarly described as having watering of the eyes and coughing during the same period. The signs were probably caused by the same H_2S exposure.

Complaints about an unpleasant odour were received from a large number of people in Edmonton and areas remote from Lodgepole. Although H_2S in the Edmonton area did not exceed 0.5 ppm, this level substantially exceeds the odour threshold of the gas.

The condition of patients with chronic respiratory disease in Edmonton and areas remote from the blowout site who were exposed to low concentrations of pollutants may have been temporarily aggravated, but insufficient data was available to evaluate this possibility.

Government departments established and applied a set of H_2S exposure limits that were designed to protect human health. If concentrations exceeded those limits, then residents would be advised, requested, or ordered to leave the area. The most commonly applied exposure limit was 15 ppm. Special limits were established for people more susceptible to H_2S but, in fact, they were not applied.

Under the direction of AE, H_2S concentrations downwind from the well were monitored by a combination of mobile and stationary monitors to ensure that if concentrations exceeded the exposure limits, the residents would be advised and would vacate the area. On six occasions, H_2S concentrations near residences were in excess of 15 ppm and residents temporarily left the area.

During the 26 days that the well was not on fire, H_2S concentrations at or near residences exceeded 10 ppm for about 31 hours and 5 ppm for 61 hours (see Table 7.1). The stationary monitors located at Lodgepole, Cynthia, and Drayton Valley recorded concentrations less than 1 ppm for 87, 95, and 96 per cent, respectively, of the total hours monitored. In Edmonton, the maximum concentration recorded was 0.5 ppm, and the overall concentrations were about one-tenth of those for the three communities near the well.

In the Panel's view, it is paradoxical that the exposure limits were not exceeded, except in a few instances for susceptible persons, yet the anecdotal evidence indicates that the emissions probably caused temporary health effects. In view of this evidence, the Panel believes that the PBOH should give further consideration to appropriate exposure limits. The need for reconsideration is even greater for those persons who may be susceptible to H_2S.

While the monitoring was effective, the communication of the plan and its results to the local people was quite inadequate. Residents were not advised about the program, and were not always able to obtain answers to their inquiries about monitoring results.

While the well was on fire, the H_2S was converted to SO_2. Because of the intense fire, the emission plume had substantial rise, and its dispersion was effective. SO_2 concentrations were substantially below the related ambient air quality standards and health problems were not evident.

7.9 Recommendations

The Panel recommends that:

1 The PBOH reconsider its H_2S exposure limits in light of the Lodgepole evidence and in particular for "sensitive individuals".

2 Information be obtained by the PBOH on the biological effects of extended intermittent and continuous exposure to moderate and low level concentrations of H_2S, such as were experienced by residents and animals during the Lodgepole blowout. This could be obtained by modern research techniques.

3 AE, the ERCB, and representatives from industry and the public develop a comprehensive centrally dispatched monitoring plan that could be implemented immediately.

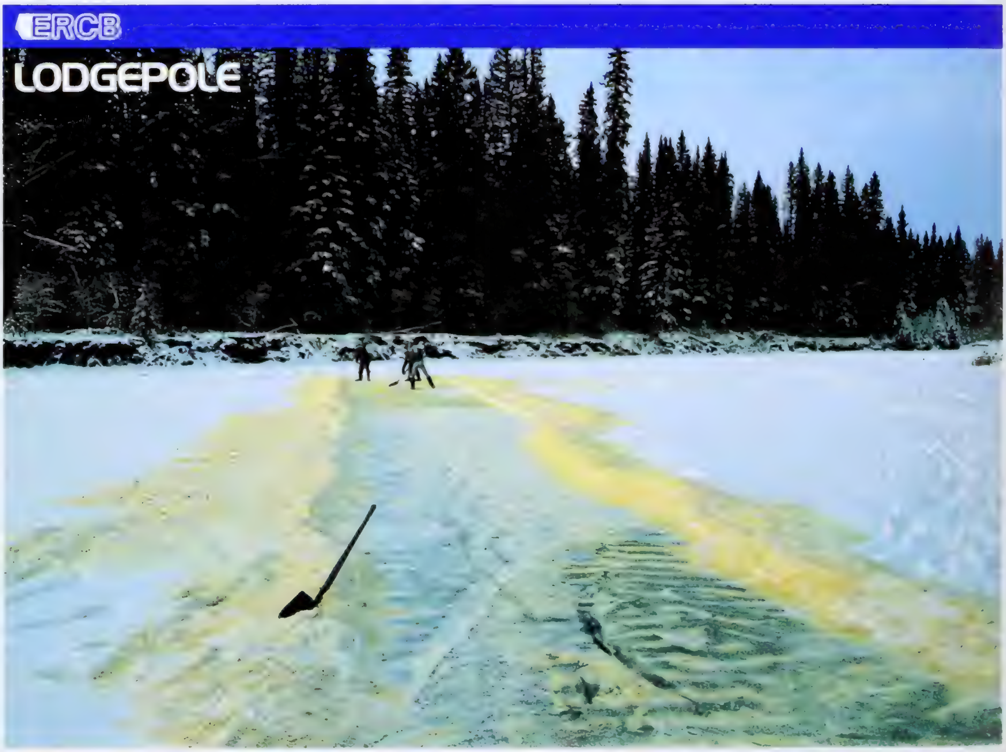
4 AE and the ERCB arrange for a comparison and analysis of actual H_2S concentrations obtained by monitors and the predicted concentrations from dispersion modelling with the objective of improving the latter capability.

5 Further consideration be given by the PBOH and other medical bodies to determine whether useful information could be obtained from a review of actual medical experience during the blowout, and to consider whether better measures can be implemented to determine the effects of emissions from other blowouts which may occur in the future.

6 Methods of providing remote rural residents with Drager units and possibly crush ampoules, and training in their use, be addressed in site-specific emergency response plans.

7 The ERCB should attempt to identify all of the gaseous contaminants, in addition to H_2S and SO_2, which could be produced by a sour gas well, since other components could also have biological significance. This type of physical chemical analysis could be carried out on material safely obtained from an existing well or wells.

8



Workers clearing Pembina River ice to assess potential damage.

Photo credit: W. Wylie, ERCB

8 IMPACT ON THE ENVIRONMENT AND ON PERSONAL PROPERTY

8.1 Introduction

During and following the blowout, Amoco engaged a wide variety of environment specialists to assist in addressing the suite of environmental problems including:

(a) air-shed evaluation (section 7 reports separately on the local area monitoring aspect),

(b) soils, vegetation, and reforestation,

(c) wildlife evaluation, and

(d) aquatic evaluation.

Others, including AE, Alberta Forest Service (AFS), and Alberta Fish and Wildlife (AFW), also pursued companion activities to address certain aspects of those environmental issues. As well, the Public Advisory Committee to the Environment Council of Alberta (PAC) retained consultants to perform a detailed post-event evaluation to determine potential adverse biophysical effects resulting from the well emissions.

The Panel finds it convenient to address the environmental impacts under two main headings:

(a) **On-Site and Immediate Area**

This area, depicted in Figures 8.1 and 8.2 and up to about 6 km from the well, was very heavily impacted by condensate precipitation and subsequent fires.

(b) **Local Regional Area**

This area, depicted in Figure 8.3 is a region some 60 to 70 km beyond the immediate site, believed by PAC to be exposed to measurable sulphur loading from the well emissions.

8.2 Background Information

The 13-12 well blowout resulted in extremely large emissions of gaseous and liquid hydrocarbons and other compounds, extending from 17 October to 23 December 1982. During the period 17 October to 1 November, the raw gas was emitting through a restricted opening of crimped 114.3-mm (4.5-inch) drill pipe still hanging in the rig BOPs. The emission rates during this period were variously estimated to be in the range of 0.4 to 0.8×10^6 m^3 per day. After the rig caught fire and burned down, and all of the debris was removed, flow was emitting from a 244.5-mm (9.625-inch) casing with no surface obstructions. Most of the post-event evaluations and evidence provided at the inquiry were predicated on estimated flow rates of about 1.1 to 1.4×10^6 m^3 per day from 1 November until the well was capped.

Following is a brief table showing estimates of the rates and nature of well emissions during the key time intervals:

DATES	RAW GAS RATE (10^6 m^3/d)	CONDENSATE FALL-OUT (m^3)	SULPHUR RATE (t/d)	EMISSIONS
Stage 1 — Raw Gas Plume				
17 Oct – 1 Nov (15 days)	0.4 to 0.8	300 – 600/d	150 to 300 primarily H_2S	Most of the raw gas, including sulphurous (H_2S) gas, dispersed over a broad area. Deposition was greatest in the local area. Local regional effects occur.
		4 500 to 9 000 cumulative condensate on site		Most condensate settled near the site on forests and frozen ground. Subsequent fire burned most of this condensate.

DATES	RAW GAS RATE (10^6 m^3/d)	CONDENSATE FALL-OUT (m^3)	SULPHUR RATE (t/d)	EMISSIONS
Stage 2 — Well on Fire				
1 Nov – 14 Nov (13 days)	1.4	1 100/d	450 (900 of SO_2)	Well on fire. Gas and condensate incinerating at point of emissions. Main products are H_2O, CO_2, and SO_2. Major impact potential from SO_2.
		14 000 cumulative incinerated		On-site soils thawed and dried out from intense heat. Forest burned and additional clearing created dry barren soil area around well.
Stage 3 — Raw Gas Plume				
14-25 Nov (11 days)	1.4	1 100/d	450 primarily as H_2S	Similar plume impacts as in Stage 1, but higher emission rates resulted in greater local regional impacts.
		12 000 cumulative on site		Condensate precipitated onto dry, exposed soils on site and a portion seeped through soil into substrata. Groundwater and nearby snow and ice-covered surfaces of Zeta Creek and Pembina River received some condensate deposition.
Stage 4 — Well on Fire				
25 Nov – 23 Dec (28 days)	1.4	1 100/d	450 (900 of SO_2)	Condensate and gas incinerated at emission point.
		31 000 cumulative all incinerated		Effects similar to Stage 2 except for atmospheric variances.

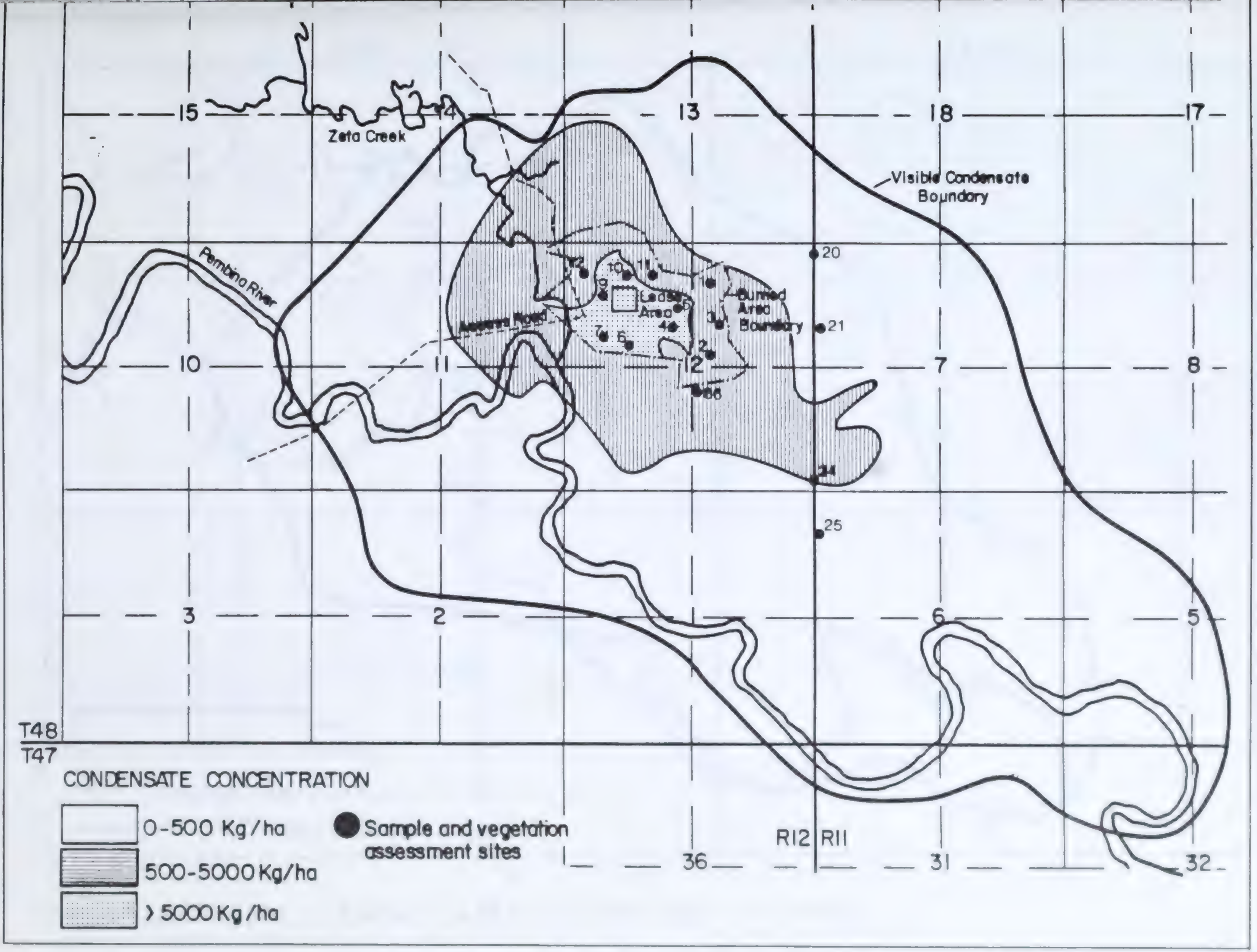


FIGURE 8.1 CONDENSATE DISTRIBUTION AROUND THE 13-12 WELL.
Reproduced from Exhibit No.173.

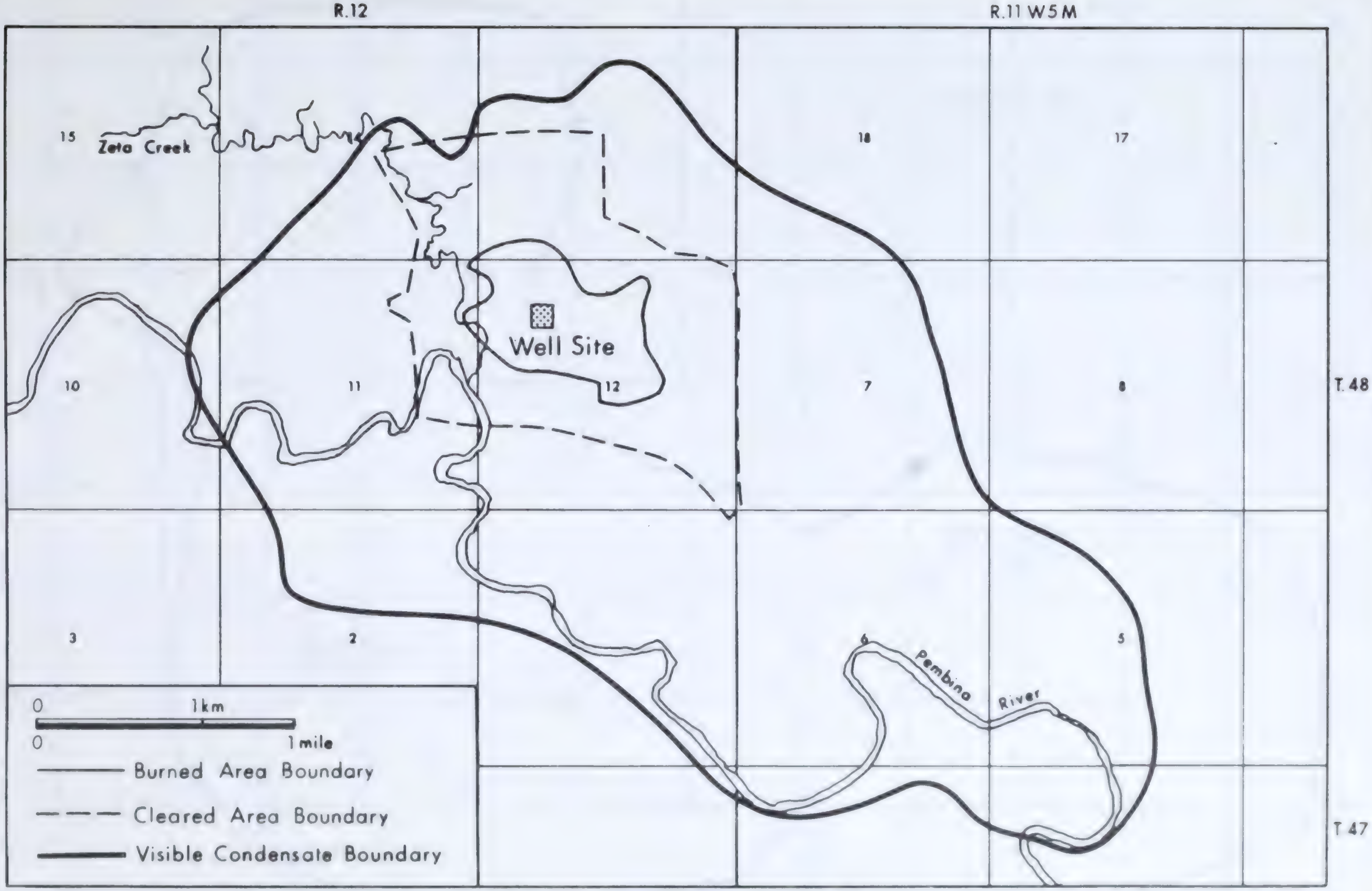


FIGURE 8.2 FOREST CLEARING AREA AROUND THE 13-12 WELL.

Based upon " Effects of the 1982 Amoco-Dome Brazeau River 13-12-48-12-W5 Well on the Environment (Soil and Reclamation Component)" Volumes 1 and 3 filed as Exhibits No. 95 and 95.2, respectively.

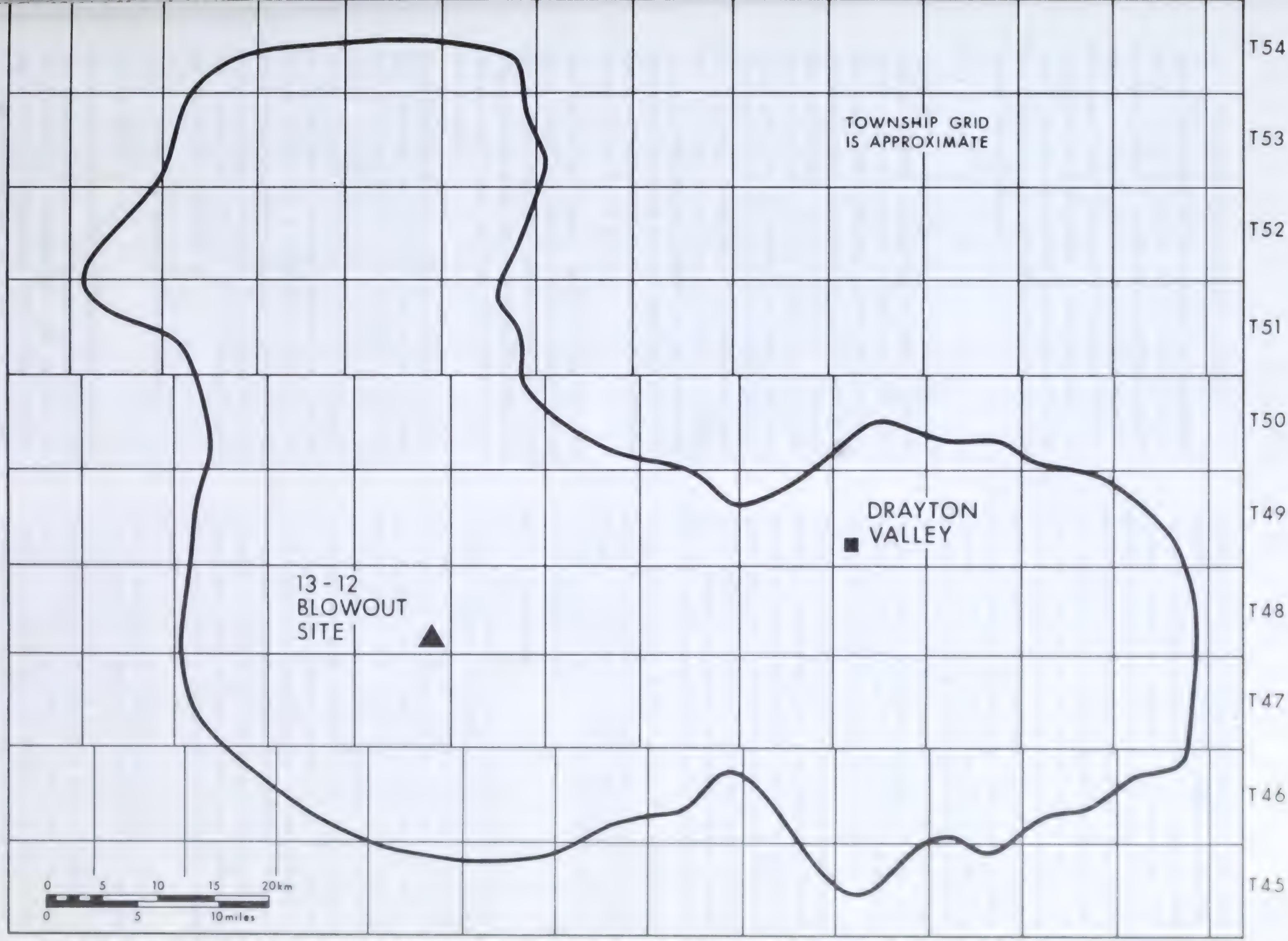


FIGURE 8.3 BOUNDARY OF MEASURABLE SULPHUR DEPOSITION AROUND THE 13-12 WELL. (AS SHOWN IN EXHIBIT NO.92).

8.3 On-Site and Immediate Area Impact

By visual observation and field sampling, after the blowout was controlled, Amoco was able to describe the area shown on Figures 8.1 (condensate) and 8.2 (fire and forest removal) as areas of intensive environmental impact. In these areas, though toxic gaseous emissions obviously would have had some effects on forest vegetation and wildlife, the most obvious and dramatic impact was that from "condensate rain and mist" and from the fires that engulfed the well-site area.

8.3.1 Air

When the well was not on fire, in order to ensure safe working conditions at and near the site, Amoco safety personnel continually monitored to determine H_2S concentrations at the well site, the staging areas (2 to 3 km away), and access routes. During this period, there were 5 half days and 6 full days when Amoco decided to halt work on the well because H_2S levels were too high. Also, a few days after the blowout, Amoco closed its base camp some 5 km north of the well because of the risk to personnel of H_2S exposure during night-time atmospheric inversions. The combination of on-site and off-site monitoring and plume observations thereafter satisfied Amoco that atmospheric dispersion was reducing plume concentrations to well below worker-tolerance levels in most areas beyond 1.5 to 3 km of the well.

After the first fire, Amoco reported finding three dead moose about 500 m from the well and a dead raven near the site. It can be inferred from the Amoco and Nabors evidence that on some days quite high concentrations of sour gas could develop and linger for some time near the well-site area.

It is evident that when the well was not on fire, relatively high concentrations of H_2S occurred near the well site on those days and nights when atmospheric conditions resulted in inefficient plume dispersion. Of the total 26 days when the well was not on fire, some of the daytime periods showed measured concentrations greater than 50 ppm near the well. It is probable that night-time conditions would have shown even higher H_2S concentrations owing to night-time inversions. These conditions would have had an adverse effect on all air-breathing beings in the near vicinity of the well.

8.3.2 Soils, Vegetation, and Groundwater

8.3.2.1 Soils

Amoco identified the visible condensate deposition boundary as shown in Figure 8.1. Amoco testified that 30 000 to 32 000 m^3 of condensate fell within this area during the times the well was not on fire. However, evaporation (estimated at 40 per cent of the condensate liquid), subsequent incineration from the lease area fires, and migration of condensate into the substrata reduced the available condensate on the surface to a relatively small amount. Surveys by Amoco in the summer of 1983 showed, except for an area of some 39 ha around the well, as shown in Figure 8.4, that only the upper 7.5 centimetres (cm) of soil contained adsorbed condensate. In these areas, the concentrations were low ($<$ 500 kg/ha) and were expected to biodegrade without problems. However, as shown in Figure 8.4, concentrations of 25 000 to 75 000 kg/ha, equivalent to a high impact oil spill, exist in 10 ha of low-lying grounds near the well and 10 000 to 25 000 kg/ha exist on another 29 ha. Amoco has concluded that the combined 39 ha, medium to heavy condensate-saturated soils areas, will require stimulation of natural biodegradation in order to achieve full rehabilitation over a period of years.

Referring to the table, the Panel concludes that the condensate emitted during Stage 1 precipitated near the well and the subsequent fire probably burned up most of it. Additionally, the Panel believes that the 12 000 m^3 of condensate that precipitated during Stage 3 (14 to 25 November) would have constituted the main source for long-term contamination of soils and groundwater.

Respecting soils only, the Panel accepts Amoco's view that although biodegradation will gradually remove the condensate, considerable reclamation effort will be required over a number of years to fully rehabilitate the more heavily affected areas.

8.3.2.2 Vegetation

Amoco filed evidence showing that in the immediate well-site area, the impact of the condensate emissions on vegetation was both major and dramatic. During the periods when the well was on fire, both forest and ground vegetation were burned or removed from areas near the well as shown in Figure 8.2. To determine longer-term impacts on forested areas exposed to condensate and other well emissions beyond the burned area, Amoco (Ecosat) used observations on vegetation impacted by the 1977 blowout as an analog. It concluded that where condensate precipitation is heavy, as in the regions shown on Figure 8.1, tree mortality would be high. Further extrapolations indicate that retarded growth will occur in other less impacted areas for a period of 2 or 3 years before resuming normal growth.

On the strength of the Amoco information and its own observations, AFS similarly concluded that survival and growth of mature trees in the moderate to heavily condensate-exposed areas would be very limited. To facilitate reforestation and to reduce fire risks, AFS required Amoco to clear-cut the areas over some 290 ha as shown on Figure 8.2 and further clearing may be required. In those regions, a reforestation program, as part of the general reclamation program for the area, is being conducted by Amoco under the guidance of AFS.

Amoco (Legge) also investigated the potential impact of sulphate-sulphur ($SO_4 - S$) beyond the observed condensate regions. Amoco (Legge) concluded that the forest ecosystem had been subjected to elevated levels of surface sulphate and that short-term modification of nutrient cycling would occur. The results would be a short-term interruption in growth rates, 2 to 3 years, as observed in similar forest areas around the 7-10 well blowout in 1977.

It is obvious that there was a major impact on forest and other vegetation in the immediate well-site area. However, apart from the heavily impacted areas shown in Figure 8.4, the Panel concludes that actions to date and planned programs will permit successful reclamation and revegetation of all areas of the site. Indeed, early observations indicate that forest recovery at the perimeters of the burn were already starting by natural reforestation much like that which occurs in a typical forest-fire burn area. For the heavily impacted areas near the well, the Panel accepts that the planned reclamation programs will ultimately be successful, though it will take many years to fully confirm that expectation.

8.3.2.3 Groundwater

Amoco stated that a considerable quantity of condensate, estimated at 18 000 to 19 000 m^3, settled onto the ground during the non-burning periods of uncontrolled flow. Since the well was located only some 350 m from Zeta Creek there was a significant potential for condensate flow into, and for contamination of, Zeta Creek and the nearby Pembina River. In addition to accumulation and flow over the surface, Amoco observed that the condensate moved laterally at some speed through fracture planes in the bedrock and seeped out at exposed bedrock faces near Zeta Creek. When this was detected, Amoco constructed a series of trenches and berms to intercept and burn off the condensate before it could reach Zeta Creek or the Pembina River.

Soon after the well was capped, Amoco drilled 74 observation boreholes to initially evaluate surficial geology and the presence of condensate in surficial groundwater aquifers. Subsequently, Amoco installed permanent casing in 54 of these to serve as piezometers to observe groundwater hydrodynamic gradients (which indicate direction of flow) and monitor changes in condensate contamination of the groundwater. Amoco concluded that possibly 1900 m^3 of condensate migrated into the shallow aquifer system. As well, it observed that there was relatively rapid migration toward the interceptor ditches following hydrodynamic gradients interpreted as shown in Figure 8.5. Except for trace amounts of condensate that may have migrated into deeper aquifers, Amoco did not foresee groundwater contamination as a future problem. However, it planned to maintain observation wells for several years until such time as it could be confirmed that no more than trace amounts of condensate were present in the local groundwater system.

The Panel notes from the table of well emissions that Stage 3 represented the most likely period for condensate contamination of the groundwater, both because of the volume of condensate that fell and also because the earlier fire had removed the snow and ice and thawed the ground. If half of the total amount settled onto the nearby burned land area and possibly one-third of that amount actually reached the aquifers, the total contamination would be some 2000 m^3. It appears to the Panel that groundwater contamination is localized near the well, can be corrected over a period of time, and is not an immediate problem because of the isolated location of the well. The Panel endorses Amoco's plans to maintain the piezometers and condensate-capture trenches for several years until the condensate is eventually dissipated and does not represent a groundwater hazard.

8.3.3 Surface Water and Aquatic Organisms

8.3.3.1 Surface Water

During the Stage 1 phase of the blowout, condensate precipitates reached both Zeta Creek and the Pembina River. This contamination problem was immediately reported to water users downstream (eg, Evansburg) and alternative sources for domestic water were instituted. Amoco took action to reduce condensate effects during the blowout, after capping, and before the spring thaw by cleaning up the site and river ice, installing spill-control booms, gravel berms, and culverts on Zeta Creek, and containment trenches to avoid contamination of surface water. The accidental ignition of the well during two extended intervals resulted in burning off much of the emitted condensate that lay on the surface in the immediate well-site area. From the viewpoint of minimizing long-term contamination of surface water, this burning off of surface accumulation of condensate proved to be a great advantage. Amoco (Stanley – IEC) reported that the water used to control ground fires and high ground temperatures near the well also tended to flow into the creek and oxbows near the well. These represented significant sources of contamination of surface waters. Subsequent observations showed that, apart from a short-term peak in hydrocarbon level which moved out with spring break-up ice, the river is now virtually free of hydrocarbons. Respecting Zeta Creek, Amoco has installed a dam and culvert water-release system that will allow surface skimming of any condensate that may be washed into the creek.

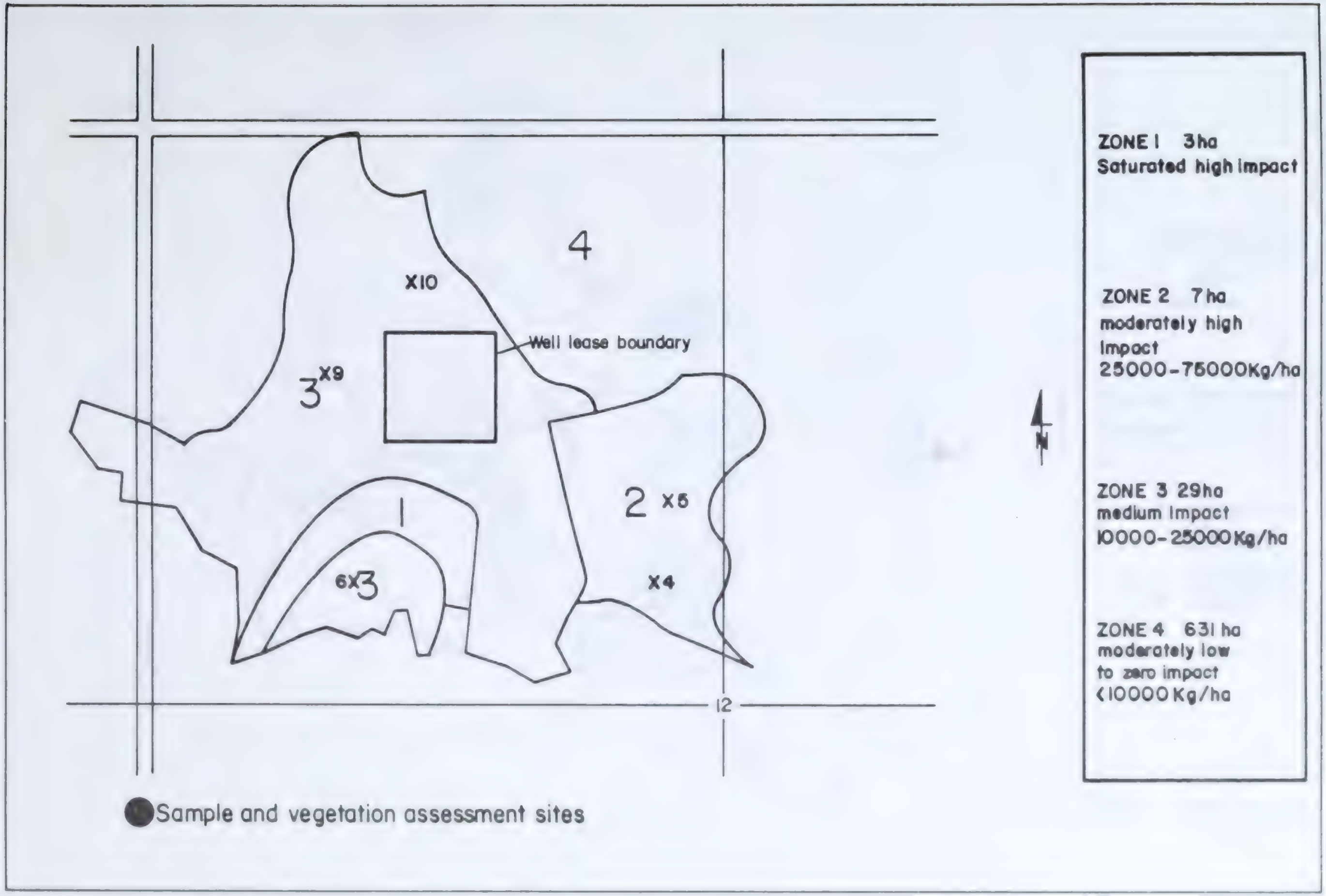


FIGURE 8.4 CONDENSATE IN SOILS AROUND THE 13-12 WELL.
Reproduced from Exhibit No.173.

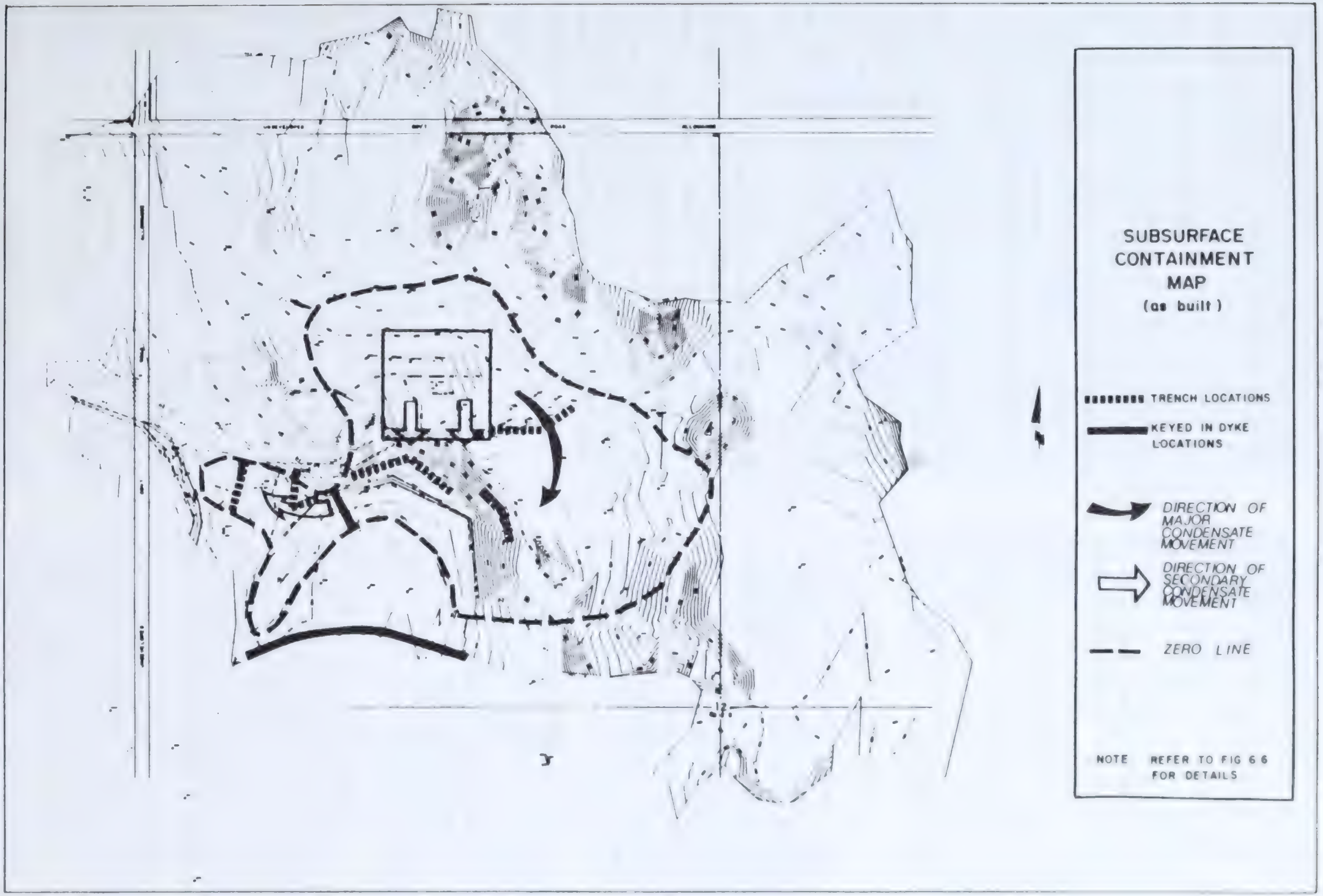

SUBSURFACE CONTAINMENT MAP
(as built)
TRENCH LOCATIONS
KEYED IN DYKE LOCATIONS
DIRECTION OF MAJOR CONDENSATE MOVEMENT
DIRECTION OF SECONDARY CONDENSATE MOVEMENT
ZERO LINE
NOTE REFER TO FIG 6.6 FOR DETAILS

FIGURE 8.5 CONDENSATE IN GROUNDWATER AROUND THE 13-12 WELL.
Reproduced from Exhibit No. 95.

The Panel is satisfied that measures to protect surface water were reasonably successful since participants stated that hydrocarbon contamination of the surface water bodies, initially detected as far downstream as Evansburg, disappeared in a few months.

8.3.3.2 Aquatic Organisms

Owing to the winter season, fish and benthic studies had to be deferred until spring, several months after the well was capped. Amoco (Stanley – IEC) found little evidence of negative effects on fish spawning. However, waxy-condensate precipitates were found in some creek muds, and these could adversely affect local populations of small benthic organisms.

Benthic organisms collected at various sites along Zeta Creek and the Pembina River showed some initial changes in species diversity, but these changes disappeared later in the year. Amoco stated that, while periodic monitoring will continue, observed effects on aquatic organisms have been relatively mild and are expected to be very short term.

The Panel believes that, while techniques such as measuring species diversity rely on some rather loose assumptions, it is probable that the effects of the blowout on benthic organisms, primarily from condensate contamination, would be very short term and should no longer be of concern. Nevertheless, the proposed monitoring surveys should be helpful in confirming those preliminary observations.

8.3.4 Wildlife

While the evaluation of wildlife impacts focused on the "on-site and immediate area", observations respecting larger ungulates necessarily extended farther afield. Amoco reported that during the blowout, three moose and a raven were found dead near the well site. The moose were found 500 m from the well in the burned area shortly after the first fire. Cause of death was not established. Amoco inferred from animal track surveys that large ungulates such as elk were avoiding the immediate well-site area during the winter but otherwise, ungulates moved about the forested areas beyond the immediate area in patterns that conformed with surveys of the general area done in 1981. A small mammal survey carried out by AFW in the cleared and perimeter areas determined a shift in species composition, probably temporary, but with no significant changes in numbers. Captured fur-bearing animals were unaffected.

The Panel believes that wildlife impacts in the on-site and immediate area, especially within the burned area, were significant. As well, the cleared area (Figure 8.1) can be expected to show changes in wildlife species diversity because of alteration of the habitat. The Panel questions whether the findings and conclusion from the AFW survey are consistent with the evidence of the local area residents when they reported on numbers of birds and wildlife, as well as effects on their livestock. The small mammal survey was restricted to an area within 3 km of the well, whereas the residents' evidence related to impacts as distant as 55 km. There is no evidence available to the Panel to examine these apparent differences. Moreover, it would not be possible to determine whether wildlife experienced the specific effects identified for livestock in the general area. Consequently, the Panel can only identify this potential discrepancy in the evidence. In any event, the Panel believes that long-term impacts on wildlife will not be adverse in a significant way though condensate-exposed forests may cause some minor adverse effects on small animals and birds for a number of years.

8.4 Local Regional Area

With respect to the area beyond a radius of some 5 km from the well, evidence concerning impacts related to only a few specific items. These primarily related to assessing effects on human and animal health and on personal property, including domestic animals, deriving essentially from air pollution caused by H_2S and SO_2 emissions during the 67-day blowout period. Potential human health effects are discussed separately in section 7 and will not be addressed in this section, but impacts on personal property are reviewed.

Amoco (Promet) developed a continuous air-shed modelling program which it combined with intensive local plume monitoring and information from monitoring sites in various parts of the province as a means of evaluating airborne environmental pollution from the well. The results aimed to show daily changes in H_2S or SO_2 over the province as a result of regional atmospheric air flows.

PAC also performed an extensive post-event study of potential sulphation impacts on the local region, using both plume-modelling and local region ground sampling and evaluation methods. AE endeavoured to evaluate the significance of both the Amoco air-shed modelling and the PAC evaluations in relation to AE's own special knowledge in plume dispersion modelling.

The Panel notes that there was a significant degradation of air quality over a very large area during the blowout. This was especially noticeable to the public during Stages 1 and 3 when raw sour gas was mixing in the atmosphere and being carried far afield. However, beyond what the Panel has classified as the local regional area (ie, up to 60 to 70 km from the well), the Panel believes that most of the biophysical and personal property impacts of this air pollution would have been of the nuisance variety.

8.4.1 Air

A wide area around the well site was exposed to airborne pollutants, specifically H_2S, SO_2, other well gases, and condensate. An analysis of condensate deposited on the ground, carried out several months after the well was capped, showed the condensate to be composed of 62.4 per cent alkanes and 37.6 per cent aromatics and other compounds. The alkanes are believed to be rather rapidly biodegradable, but the aromatics are more difficult to break down. Amoco estimated that 40 per cent of the condensate evaporated into the atmosphere during the blowout. The nature and fate of the evaporate-component were the subject of speculative questions during the inquiry: ie, what were its components?, would concentrations be sufficient to have adverse influence on the air?, would it have noticeable effects on humans or animals if breathed in?, etc. However, there was no evidence presented to evaluate these questions.

Respecting effects from the plume, the Panel is inclined to accept that the focus of ground level impacts, if measurable, would tend to be within an area 60 to 70 km from the well as outlined by PAC (Figure 8.3). Anecdotal evidence from local residents support that concept. At the same time, the Panel understands that mixing of the plume in the upper atmosphere and long-range transport of it to remote regions as calculated by Amoco (Promet) is a reasonable and widely accepted meteorological proposition. Odour complaints hundreds of kilometres from the source also tend to verify that concept.

PAC focused its attention particularly on possible cumulative sulphur deposition in the local region that could be caused by plume impingement on the ground. PAC assumed a total sulphur emission rate of some 485 tonnes per day based on an assumed raw gas rate of 1.1×10^6 m^3 per day and 30 per cent H_2S. Using the SULDEP Model, it predicted that sulphation impingement would range up to 35 kg/ha in a region as shown in Figure 8.3. From ground sampling focused in an area easterly and southerly from the well, PAC first believed that it had generated a reasonable corroboration of calculated plume-impingement sulphation using ground leaf litter sample data. It later acknowledged that there were problems in sampling and measuring that made interpretation of results complex and potentially ambiguous.

AE contended that PAC had erred by introducing forced, abnormally high deposition velocity rates in the SULDEP Model. AE implied that the proper velocities, considering the presence of snow cover and relatively cool, arid, winter conditions should have been only perhaps one-seventh those assumed by PAC. If so, the calculated sulphur fall-out and retention in the high-impact areas would then be calculated as possibly only 2 to 5 kg/ha, rather than 15 to 35.

Though Amoco (Promet) did not specifically examine the question of cumulative sulphur deposition in the local region, its air models showing daily changes indicated that the bulk of the well emissions were being lifted and mixed largely in the upper atmosphere (300 to 500 m above ground level) and being transported over hundreds of kilometres from the site. By inference, sulphur fall-out in the local region would have been modest and not likely of measurable impact on the local regional ecosystem.

The Panel has considered potential maximum ground-level concentrations of SO_2 including provision for plume momentum rise. From these, the Panel concludes that maximum ground impingement would probably occur from 10 to 20 km from the well. This is similar to areas that PAC has described as having maximum sulphation impact in a local region as shown on Figure 8.3. Respecting leaf litter sulphation sampling, the Panel believes that the PAC programs would have to be subjected to more extensive evaluation to establish whether it is an effective means of evaluating such impacts. The Panel believes, taking into account the low adsorption possibility for the winter season, the PAC calculations overstate the cumulative sulphation effect and that the actual levels of cumulative sulphation impact would be significantly less than predicted by PAC.

In summary, the Panel believes that ground-level sulphation from the 13-12 blowout, because of the winter season, would not likely have had measurable effects. Within cultivated land areas, even if loading was as high as the values submitted by PAC, crop uptake in the subsequent summer growing season would have had a very good chance of masking incipient soil acidification effects. Also, because the emissions occurred in the non-growth winter season, indirect assessment of sulphation by measuring possible damage to natural vegetation is essentially eliminated.

In spite of those conclusions, the Panel believes there are two aspects of the subject that warrant further pursuit. The Panel recommends that the ERCB and AE consider sponsoring a symposium to hear expert views on the two general subjects of plume modelling/plume impingement and sulphation ground sampling analysis techniques. Bringing concerned members of the public, including those with agriculture, forestry, and general environmental interests, together with meteorological, biological, and soils experts would seem to be a worthwhile follow-up to this most significant sour gas blowout event.

8.4.2 Personal Property

8.4.2.1 General

The question of possible financial losses by local residents was expressly excluded from consideration under the terms of the inquiry. Amoco advised that a number of claims for personal property damage were being paid by Amoco and other claims were in litigation.

Anecdotal evidence was presented by several local area residents regarding effects on buildings, machinery, equipment, fences, crops, and livestock from the blowout emissions. These impacts were thought to be due to H_2S when the well was not on fire. There was also speculation on possible problems from other pollutant components in the raw gas and some reference to potential longer-term effects from sulphur deposition on soil.

Several participants testified that the paint on their buildings turned black, which would be consistent with a reaction between H_2S and certain paints. Evidence was also given that silverware was blackened, electrical contacts were corroded, some machinery became non-operational, and fences were discoloured. The Panel recognizes that these effects, which occurred during the blowout phase, constitute an annoyance and some financial loss to residents. The Panel believes that since the cause has been removed, no further effects are likely.

8.4.2.2 Crops

Testimony on the effects of the blowout emissions on crops was scarce. Since the blowout occurred in winter, no growing field crops were affected, though it was reported that some houseplants died. There was evidence from local farmers that in the following summer, alfalfa and hay crops were as low as one-half to two-thirds normal yields. Some suspected there were direct adverse effects from the well emissions. Countering this view, AA submitted that seasonal factors such as low moisture and adverse growing season temperatures were more likely the causes of the reduced productivity observed in 1983. The Panel notes that a very comprehensive protocol would need to be in place before and after the blowout event in order to confirm, even qualitatively, such effects, because weather and agricultural practices have a gross masking effect on crop performance. The Panel believes that sulphur deposition rates were such that possible adverse effects would not likely extend beyond one growing season.

8.4.2.3 Livestock

The question of airborne well emissions from the blowout and their effects on livestock received considerable attention at the inquiry. The Panel did not receive detailed evidence on individual claims for losses due to such effects because evaluation of such claims was outside of the terms of reference. However, the Panel did hear considerable evidence respecting the general impact of the blowout on livestock from a number of those who appeared on behalf of PASGEC, and from individuals appearing at the informal session in Drayton Valley.

Many of the signs of physical distress described in animals had some similarity to the human symptoms described by those appearing at the inquiry. For that reason, a description of the signs was presented in section 7.2.4 of the report and is not repeated here. The Panel recognizes that a number of the individuals appearing at the inquiry referred to effects on livestock. These included spontaneous abortions or other effects on the birth rate or weight and quality of newborn calves, weight loss in mature animals, and reduced milk production. Although some of the participants presented documents to support their allegations, the Panel does not have sufficient information to draw definite conclusions respecting the effects. For example, one witness presented milk delivery statistics which revealed a reduction in milk production for his dairy herd, but data respecting all other variables which could affect production were not available. Thus, a sound scientific conclusion could not be reached regarding the possible financial effect of the blowout on the dairy herd in question.

In another matter related to livestock, staff of the Alberta Environmental Centre attempted to determine the effects of the emissions on certain important enzymes of cattle. Blood samples were taken from cattle from ten herds in the affected area during the blowout and subsequent to the capping of the well, and also from two control herds in the Vegreville area.

These studies showed that some statistically significant biochemical perturbations did occur in animals within the exposure area. In all cases, however, the changes appeared to be transient and reversible. The investigators advised that these results are highly experimental in nature and must be interpreted with considerable caution, particularly when assessing suspected clinical disease in the animals. At present, the importance of these results is not known.

8.4.2.4 Financial Compensation for the Public

There is no mention in the terms of reference for the inquiry of the question of the monetary impact of the blowout on the public and the Panel clearly does not have jurisdiction to determine whether such impacts occurred, or whether compensation should be paid.

For this reason, the Panel and most participants avoided discussing these matters, but compensation was nevertheless referred to on a number of occasions by participants from the public during both the formal and informal sessions. These comments and the many references in the media to the subject prompts the Panel to comment on it in a general way in this report. However, the Panel is not expressing any opinion as to whether the monetary impacts referred to at the inquiry as a result of the 13-12 well blowout were real or otherwise.

There is no question that monetary impacts can result from sour gas blowouts and that some of these were imposed on members of the public. Indeed, Amoco indicated that it had voluntarily settled several damage claims and that others were under negotiation. The comments from members of the general public indicated that problems stemmed from the determination of whether damage had been incurred and the long delays in settlement. In the Panel's judgement, part of the dissatisfaction of the public regarding sour gas blowouts is because there are real or perceived monetary impacts and nuisances which might not be compensated. Many spokespersons for the public suggested that these concerns would be rectified if the industry was forced to carry no-fault third-party damage insurance. The Panel questions whether this would be the case but recognizes that there is a problem which should be considered. The Panel recommends that the ERCB, the industry, and appropriate Government departments give this matter further consideration and notes that the matter of blowout insurance is currently being examined as a follow-up to recommendations in the Phase 2 report.

8.5 Reclamation

Only the immediate area around the well site is likely to require reclamation. Evidence was presented on the sulphur deposition beyond the immediate area, but effects were stated to be small or negligible. Nevertheless, the Panel believes that soil and vegetation should be monitored for several years for at least 10 km in the downwind directions from the well site.

The burned-off soil area next to the well and the clear-cut area extending several more kilometres are planned for reclamation. Seedlings were being prepared in 1983 for planting in 1984. Soon after the well was capped, a committee was formed to co-ordinate damage evaluation and rehabilitation chaired by the ERCB with AFS and AE having key roles. This committee approved or requested some site clean-up measures, and at the time of the inquiry, Amoco was working with the committee to develop long-term reclamation plans. The Panel understands that Amoco's reclamation activities under direction from this committee are well under way.

8.6 Summary of Panel's Views

Significant short-term environmental effects from condensate, H_2S, and SO_2 were experienced during the blowout period, particularly in the area closest to the well.

On and near the well site, over an area of about 300 ha, there were major impacts on vegetation and soil, and lesser impacts on surface water, groundwater, benthic organisms, mammals, and birds. Some of these impacts were ameliorated by quick remedial actions.

Due to the large quantity of condensate on the vegetation and in the ground, there will continue to be impacts near the well site for some years on trees, groundwater, soil, and benthic organisms. Again, remedial steps have been taken to reduce some of these impacts.

To overcome the major impacts in the vicinity of the well, a program of short-term remedial measures and longer-term reclamation has been established. The program is comprehensive and should permit successful environmental rehabilitation of the impacted area.

Sulphur emitted from the well, primarily in a gaseous form, was eventually deposited on the ground over an area of hundreds to thousands of square kilometres. Although the evidence submitted on the rate of deposition was conflicting and none of the estimation methods available are scientifically proved, the Panel believes that even in the more heavily impacted area within a radius 60 to 70 km around the well, the extent of sulphur deposition was relatively low. There is no evidence that these levels of sulphur deposition would have measurable harmful effects on soils, vegetation, or water bodies.

There were effects during the blowout on personal property, some being tangible and others in the form of nuisance effects. Effects on livestock, in particular, were observed during the blowout phase, but severe short-term or long-term effects are difficult to prove. Human health effects are dealt with in section 7.

8.7 Recommendations

The Panel makes the following recommendations with respect to environmental matters.

1 AE and other appropriate Government departments should establish a protocol for improved sampling and analysis of soil and vegetation that would provide a means of evaluating impacts of sour gas releases on soils and vegetation if a blowout occurs in future.

2 AFS should co-ordinate long-term monitoring of impacts on the biosphere in the "on-site and immediate" area of the 13-12 well, plus adjoining areas of the blowout, as defined in this report.

3 AA should develop a protocol to enable the gathering of timely and relevant data on agricultural activities if another serious sour gas release occurs.

4 AA should consider conducting an on-going examination of livestock in the general blowout area to determine if effects of long-term exposure to H_2S can be found.

5 The ERCB, the industry, and appropriate Government departments should consider ways of dealing with concerns of the public respecting monetary impacts on the public resulting from sour gas blowouts.

6 The ERCB and AE should arrange a symposium to hear expert views on plume modelling/plume impingement and sulphation ground sampling analysis techniques.

9

Well-site workers' discussion.

Photo courtesy Standard Safety & Consulting Services (1978) Ltd.

9 COMMUNICATION AND CO-ORDINATION

9.1 Introduction

PASGEC, as well as other participants, expressed serious concerns about the extent to which the public had been kept informed about the blowout and its impacts. They contended that the communication efforts had been totally inadequate and, as a consequence, the public had been subjected to fears about their safety and health and had not been provided with information necessary to make reasoned decisions about whether to leave the area or not. Moreover, PASGEC contended the inadequacy of the information conveyed, and the perceived reluctance to provide information to the public, led to misunderstanding and distrust by broad segments of the public of those in authority over the blowout. PASGEC contended that much of that misunderstanding and distrust occurred because the media were left to provide most of the information and their reports were designed to provide a "story" rather than facts. Consequently, reports were sometimes contradictory.

The ERCB and several Government departments conceded that neither their individual nor combined efforts to inform the public about the blowout had turned out to be satisfactory. They generally recommended that different procedures should be followed to better inform the public should a similar event occur in the future.

In a somewhat similar vein, various participants in addition to PASGEC expressed concern regarding the effectiveness of co-ordination of activities by parties having responsibilities respecting the blowout. It was alleged that jurisdictions overlapped, actions were sometimes contradictory, no single party was clearly responsible, and overall, actions were less than satisfactory.

The primary emphasis for these allegations of inadequate communication and co-ordination related to the protection of the health and welfare of the public.

In this section, the Panel reviews the communication efforts by each of the parties, assesses their effectiveness, and makes recommendations. Similarly, it reviews the effectiveness of co-ordination between parties and recommends certain changes.

9.2 Communication with the Public During the Blowout

9.2.1 Amoco

Amoco indicated that it had provided information to the public through the mass media either formally, by press releases, or informally, through telephone contact and interviews with the media. Also, it had stationed a public affairs specialist in Drayton Valley during the blowout to assist in its program.

In terms of formal contacts, Amoco issued 33 news releases, held 6 press conferences, and responded to numerous media inquiries. It also arranged for a fly-over of the site and three visits to it by media representatives, released film footage from the site, and had the company president appear on a television phone-in question-and-answer program. Amoco explained that it initially reported only significant happenings at the site, and since little was taking place on many days due to weather or other problems, Amoco reduced its media contact. It said that during these periods there was no news to release and so nothing formal was done.

After possible health effects became a serious issue, Amoco began making daily news releases concerning the well and also issued statistics related to absenteeism at its Drayton Valley office, which were intended to demonstrate that detrimental health effects were not occurring. At this time, Amoco did not have on-site medical experts specializing in the effects of H_2S on human health. It made information available respecting work standards for H_2S exposure in an effort to illustrate that health standards were significantly different than environmental standards. Amoco was critical of the media for emphasizing the ambient air quality standard, of 0.01 ppm H_2S for a 1-hour exposure, when reporting the results of monitoring for H_2S levels related to the blowout.

Immediately following the blowout, on 18 October, Amoco personnel and RCMP officers visited residents of Lodgepole and informed them of the situation and the possible need to evacuate. They also informed farmers and personnel at work sites in the area, such as petroleum plants or lumber mills. On 23 November, when H_2S levels at Cynthia were increasing, Amoco initiated notification of residents of the possible need to evacuate, but ceased notification before it was completed as H_2S levels declined.

Amoco set up a 24-hour phone system, manned by senior personnel, to receive complaints; however, it did not advertise the number as it believed Amoco was well known in the area and could be easily contacted. It made arrangements for monitoring equipment to be dispatched to particular areas when complaints were received reporting strong odours, and attempted to provide assurance and advice in response to general complaints. Amoco indicated that when it contacted residents in the area close to the well, it advised them that if they had special health problems, they could move to Drayton Valley or Edmonton and be accommodated at Amoco's expense.

9.2.2 ERCB

The ERCB issued a fire-hazard order on 19 October and arranged with AFS to have it notify known forest users such as campers, trappers, and timber operators.

In terms of communicating with the public, the ERCB staffed its Drayton Valley office 24 hours per day during periods when the well was not on fire to respond to complaints about H_2S odours. It initially referred incoming complaints to Amoco, but as the number increased, it began to register them prior to notifying Amoco, and recontacted the complainant in an attempt to better deal with the matter.

The ERCB acknowledged that it did not have a planned information service available during the blowout. The only press release it issued was on 26 November, more than half-way through the blowout period. At that time, it announced that Amoco would be given one more opportunity to cap the well and if this was not successful, the drilling of a relief well would be ordered.

9.2.3 AE

AE played the lead role in terms of communicating with the public by Government departments and agencies. It issued the first of 14 press releases on 19 October and they were issued fairly regularly during the periods when the well was not on fire. In response to questions respecting the distribution of the press releases, AE said they were released to the general government distribution service.

AE did not review the wording of its press releases with other Government departments or agencies nor did it know if others were issuing releases. AE considered that it was making a reasonable effort to convey information to the public through its press releases, responses to telephone inquiries, individual responses to media inquiries, and press briefings or interviews. It did state, however, that an improved system for communication with the public should be developed for possible future emergencies.

AE also made a telephone number available to the media so they could obtain recorded data about H_2S concentrations in the city of Edmonton. It also has a complaint number which is listed with other emergency numbers in the telephone directory, but AE did not specially advertise that number in newspapers or on the radio during the blowout. It received 1438 complaints during this 67-day period, compared to 300 to 400 in a typical year. AE relayed general information respecting H_2S in response to the complaints as well as referring calls to SS&CH, family physicians, and the Medical Officer of Health.

AE contacted downstream users of water from the Pembina River with respect to the blowout. It did not provide specific monitoring details to residents in the area, including Cynthia during the 22 and 23 November incident when relatively high readings were occurring. It did, however, conduct a follow-up survey in the area on 26 November to see how effective the contact system had been during the incident.

9.2.4 SS&CH and PBOH

SS&CH did not issue press releases during the blowout as it knew AE was doing so and believed that limiting public releases to only one government source might avoid confusion. It did, however, have several interviews with the media, and wrote one letter to the editor of an Edmonton paper to correct misinformation on health standards. SS&CH received 1477 calls, mostly relayed from AE, which were responded to by an official of SS&CH.

A booklet on health information and H_2S was prepared by the PBOH as a result of the blowout, but it was not available until after the blowout. Also, officials of the department visited the area to make information on health available, but again, after the blowout.

SS&CH acknowledged that it could have done a better job of making health information available to the public.

9.2.5 Other Government Departments and Agencies

AA did not have extensive contact with the public during the blowout but responded to the 10 to 15 inquiries it received. It did not issue press releases or provide any information regarding the effects of the blowout on animals during the period in question, except on request. Two division veterinarians visited several farmers in the area on 2 December, and an official discussed H_2S toxicity in animals at a meeting in the area in February of 1983 after the well had been capped. Alberta Disaster Services (ADS) indicated that it received only a few calls and AFS stated that it assisted in notifying forest users of the blowout. None of the other Government departments or agencies reported communications with the public during the blowout.

9.2.6 Others

The Alberta West Central Health Unit (Health Unit) received telephone complaints and gave advice where possible. Its health inspector and health nurses were frequently in contact with the citizens in the area, and conducted a number of clinics during the blowout. The Health Unit gave advice on health, referred individuals to physicians, and in some instances advised leaving the area. It also gave media interviews on request, both during and after the blowout.

The Town of Drayton Valley contacted schools and hotels and notified them of the emergency. It did not inform the residents of the town that evacuation was only a remote possibility.

The RCMP responded to calls and referred questions respecting news of the event to Amoco. On 18 October, it notified residents of Lodgepole of the blowout, and was prepared to assist in evacuations if necessary.

9.2.7 Media

As would be expected, the media was the main source of direct information for the public during the blowout. The Panel has analysed several hundred news clippings generated during that period in an effort to determine if there was a pattern in the number of stories and in their messages.

In the days immediately following the blowout, the event was being reported primarily as a news item and although there was a recognition that the well was blowing sour gas, there was not a concerted effort to address potential health effects. Most news reports indicated that capping of the well could be expected within days. As the blowout continued and the odour became noticeable more frequently for larger numbers of people, the emphasis of reporting shifted towards questioning what went wrong at the well and whether health effects would result from the sour gas being released. When the well caught fire for the first time, the fire itself and the manner in which it occurred were news stories but the reporting on health effects of the blowout appeared to decrease.

The situation changed substantially after the fire had been extinguished to allow capping efforts to continue and two Wild Well fighters died from H_2S poisoning. The deaths themselves were a major story, and there was a further increase in the number of stories and the level of questioning and skepticism respecting the handling of the entire matter. The frequency of blowout stories appeared to be about double for the period following the deaths on 16 November as compared to the previous period. A further tragic death in the area due to exposure and in no way caused by the blowout, nevertheless, had the blowout as a background in many of the news reports, thus increasing public awareness of the problem.

In the period following the workers' deaths, conflicting stories respecting effects, particularly on health, became more frequent. Information about previous H_2S related deaths in Alberta and elsewhere were being published, and with no central source of good information available, some of the stories were contradictory and at least confusing, if not inaccurate. This likely occurred because many of the statistics used in the stories were obtained by informal contacts with individuals, some of whom might not have had access to the kind of information being sought.

Many claims and counter claims by experts were being reported and the resulting confusion and increasing concerns on the part of the public increased the importance of stories on the blowout and on H_2S. Much of the reporting during this period dealt with health standards and there was confusion respecting environmental standards, occupational standards, and standards for sensitive individuals. Some doctors were being quoted as indicating that a serious health problem existed, at least for certain individuals, while others were claiming there was no long-term problem.

Reporters during this period appeared also to emphasize to a much greater extent questions as to the cause of the blowout, the performance of Amoco in drilling wells, and the adequacy of the ERCB's control regulations and its enforcement of them. Stories of this nature continued after the blowout was controlled as pressure mounted for a full public inquiry into the matter.

Mr. Struzik, a reporter with the Edmonton Journal at the time of the blowout, appeared at the inquiry. He indicated that he had made serious efforts to obtain all possible information but that Amoco was more difficult to obtain information from than is usually the case in major news events. He also said he contacted many doctors and agencies respecting health effects and standards, and reported the information given to him even when it was conflicting. When questioned, he admitted he did not attempt to explain the difference between the ambient air standards and the occupational exposure limits for H_2S. Mr. Struzik acknowledged that he did not have technical expertise in the subject matters he was reporting on, but suggested that this was not essential to proper reporting. He pointed to a serious lack of co-ordinated communications on the part of Amoco and government officials as a serious deficiency in reporting on the blowout.

9.3 Assessment of Communication Efforts

The evidence presented at the inquiry amply demonstrates the serious communication problems experienced by the public during the blowout, and the consternation experienced when the well was emitting H_2S gas. For those living in the immediate area, and to a lesser extent those residing in more distant centres, the emissions frequently caused offensive odours, which for many led to nausea and the other health-related effects described previously. In addition, the public was conscious that under certain circumstances the emissions could be lethal, but very little specific information was provided about safe limits and how these were being monitored and controlled. Of particular concern to the public was whether special precautions should be taken for individuals considered to be more sensitive, such as the very young or old, those suffering from respiratory ailments, and pregnant women.

The Panel notes that both Amoco and AE issued many press releases and were attempting to communicate with the public. However, the information provided respecting possible health effects was general and to some extent required acceptance that the public's interests were being fully cared for. The information frequently did not satisfy the public since it was not sufficiently specific to permit individuals to make their own decisions about whether they were at risk and whether or not they should be taking appropriate action. A complicating factor was that the media reports were sometimes "sensational" and tended to increase concerns rather than increase knowledge and, therefore, understanding. For example, the article titled "Danger lurks in darkness in pursuit of toxic cloud" did little to inform the public. It stated the concentrations were "... 1400 times above the provincial acceptable standard". It did not explain that the "acceptable standard" was based on the odour threshold and not on health factors and that the maximum concentration referred to in the article was only slightly higher than the occupational health standard exposure limit of 10 ppm for an 8-hour period.

While those persons living in the immediate area of the blowout were generally aware that monitoring operations were being conducted, they did not receive specific information about the monitoring program or its results. Consequently, they were completely dependent upon the company, the Government departments and agencies, and the media for information of the situation as it changed from day to day.

The Panel agrees with the consensus of inquiry participants that the communication program was deficient and that, in the event of another blowout, a more open and informative approach should be adopted. Moreover, the Panel believes that for the communication program to be effective in any situation involving the public to such a major degree, there must be provision for two-way communication. In other words, not only is it necessary for the public to understand the plans and actions of those responsible for regaining control of the well and protecting the public, it is also necessary for those in charge to understand, appreciate, and respond to the concerns of the public. In an incident such as the Lodgepole blowout, the Panel believes steps should be taken to ensure that there is a mechanism whereby those making decisions are fully aware of public concerns. Indeed, that information is a vital ingredient in assessing alternative courses of action in regaining control of the well. Had all of the information respecting public concerns been available during the Lodgepole blowout, the decision to cap the well while it was on fire might have been taken earlier, thereby reducing the fears and concerns of the public. The Panel believes it significant that the reaction by the public to the blowout seemed to be greater during the second period that the well was not on fire than during the first period. If the decision had been made to cap the well while it was on fire at that time rather than extinguishing the flame, many of the concerns and problems that subsequently developed might have been avoided.

Finally, the Panel believes that special efforts must be made to ensure that the media is fully informed in order that it can properly carry out its essential role in informing the public. A well blowout is almost certain to be news and should be treated in that manner with special communication services and facilities. Otherwise, communication difficulties most certainly will develop.

9.4 Recommended Communication Program

The Panel agrees with PASGEC that:

> "The more relevant events and decisions are, the greater the need for effective communication. Events are made more serious, and relationships are strained and upset, when there is no communication, communication is of poor quality, or is inadequate."

A well blowout which results in the emission of large volumes of H_2S gas is a very significant event for the people that may be affected by it and therefore requires a carefully planned two-way communication program. Furthermore, because of the need for immediate action in the event of a sour gas blowout, the Panel believes that a communication program should be ready so that it can be implemented immediately. Based upon the views expressed at the inquiry, particularly by participants from the general public, the Panel believes the communication program should provide, at a minimum, the following kinds of information:

(a) details of the blowout, plans for regaining control of the well, and progress reports on control efforts,

(b) details of emissions from the well and how they might impact on the public, both from a safety and a health point of view, as well as nuisance and discomfort,

(c) details of safety and health standards and the basis for them,

(d) details of all monitoring programs and the results, and

(e) details of evacuation plans, the basis for them, and how they would be carried out.

Additionally, the program should be structured to include:

(a) provision for advice and consultation for citizens concerned about special situations,

(b) arrangements for input by the public, and

(c) arrangements for the media to become better informed.

The Panel believes that steps should be taken by the appropriate Government departments and agencies, together with representatives of the industry and the public, to develop a detailed communication program. It would incorporate the above objectives and could be implemented immediately in the event of another serious blowout.

Because of the experience gained by PASGEC during the 13-12 incident, the Panel recommends that representatives from that group be included as public participants in the planning exercise. Additionally, the evidence given at the inquiry should be reviewed in detail because of the many suggestions put forward at that time.

9.5 Co-ordination of Responsibilities and Activities by Government Departments and Agencies

Government departments and agencies that had some level of jurisdiction in the 13-12 incident included: ERCB, AA, AE, ADS, OH&S, SS&CH, PBOH, E&NR, RCMP, County of Parkland No. 31, Improvement District No. 14, County Police, Town of Drayton Valley, Alberta West Central Health Unit, and the Drayton Valley hospital.

Co-ordination of work at the blowout site appeared to be effectively handled but evidence at the inquiry indicated a potential for confusion with respect to:

(a) the monitoring program,
(b) establishment of health standards,
(c) evacuation of residents,
(d) ignition of the well, and
(e) communication with the public and media.

In the case of the 13-12 incident, the Panel believes that while the potential for confusion and contradiction existed, the extent to which they actually occurred was minimal even though media reports dispute this. On the other hand, they were perceived by the public to be rather significant at times, primarily due to the poor communication system. While areas of responsibility may not have been defined with precision at all times and communication of the situation to the public was less than ideal, the co-operation between the departments and agencies was generally effective. Nevertheless, the Panel believes that this question should be addressed further.

Several of the participants suggested that the best way of avoiding potential problems would be by the establishment of a single command post through which all activities involving the public would be funnelled. The Panel supports that concept. The disaster plan recently approved and circulated by the Government, "Peacetime Emergency Operations Plan For a Sour Gas Release", developed by ADS, incorporates this concept and provides for the ERCB to be the co-ordinating body. The document is included in the report as Appendix 8. The single command post provides a clear, well defined means of furnishing information and responding to questions by both the public and the media. Within the government service, it similarly provides an effective co-ordinating mechanism. Additionally, it permits the involvement by the public in an appropriate manner.

A second suggestion that appeared to have general concurrence was the establishment, ahead of time, of a plan of action which would be detailed but would be sufficiently flexible that it could be used in the event of any such emergency. Reference was made at the inquiry to Amoco's emergency response plan and to the plan of ADS discussed above. The Panel understands the ADS plan incorporates the most recent views of the various Government departments and agencies.

The Panel believes the emergency plan should be reviewed and consideration be given in the review to the recommendations in this report.

9.6 Summary of the Panel's Views

Despite efforts by involved parties, particularly Amoco and AE, the Panel concludes that communication with the public was not effective during the Lodgepole blowout. A plan is needed which would ensure that an efficient two-way communication program would be quickly put into action in the event of any future emergency.

Co-ordination among Government departments and agencies was reasonably efficient but was not always perceived as such by the public. A plan clearly setting out responsibilities should be prepared so that the departments and agencies clearly know when and how to act and so that the public are aware that co-ordination is effective.

9.7 Recommendations

The Panel recommends that:

1 A model communication program, along the lines suggested in section 9.4, be developed by appropriate Government departments and agencies with input from the public and industry.

2 The "Peacetime Emergency Operations Plan For a Sour Gas Release", recently issued by ADS, be reviewed in light of the Panel's recommendations.

3 The establishment of a "command post" organizational structure be confirmed and implemented for all significant blowouts.

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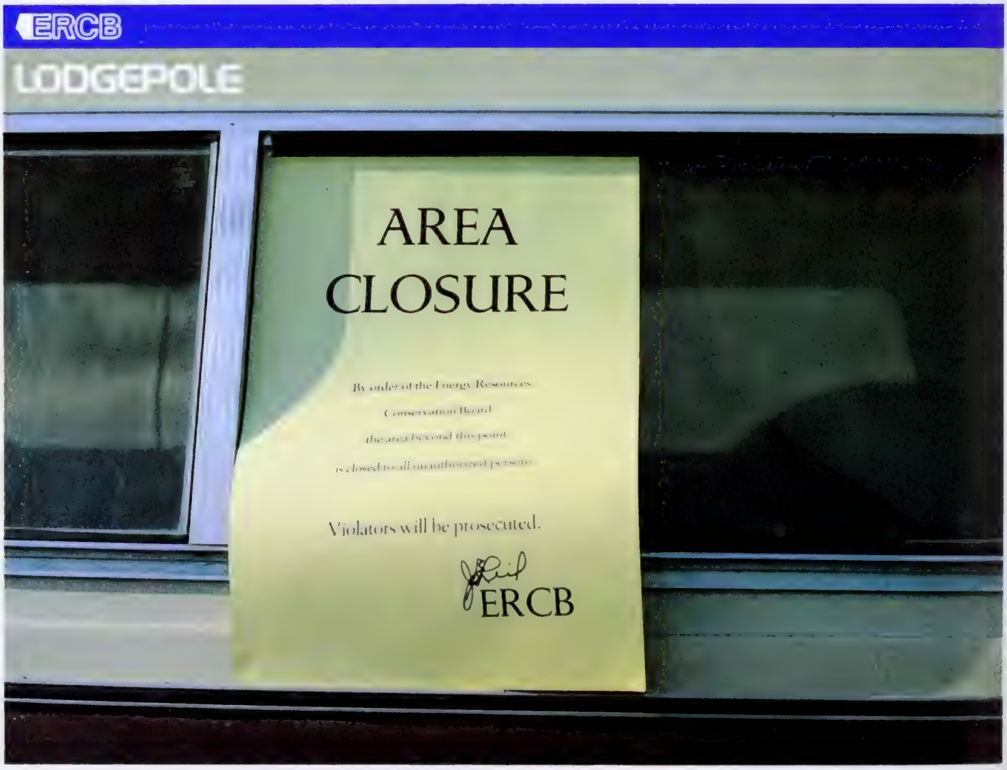
ERCB
LODGEPOLE
AREA CLOSURE
By order of the Energy Resources
Conservation Board
the area beyond this point
is closed to all unauthorized persons.
Violators will be prosecuted.
ERCB

Posted-area signs used to alert the public.

Photo credit: W. Wylie, ERCB

10 ADEQUACY OF ERCB RESPONSES FOLLOWING THE BLOWOUT, AND ITS REGULATIONS, POLICY, AND PROCEDURE

10.1 Introduction

This section of the report is intended to assess the role which the ERCB played in the blowout of the 13-12 well. It deals with the response of the ERCB to the blowout and evaluates whether it was consistent with the then existing regulations and policies. Of even greater importance, it also comments on the adequacy of those regulations and policies and recommends changes on the basis of the experiences at the 13-12 well.

The adequacy of the ERCB's involvement is discussed for each of the following three aspects of the blowout:

(a) drilling operations,

(b) operations to regain control, and

(c) impact on the public.

10.2 Drilling Operations

10.2.1 Well Licensing Requirements

The 13-12 well was licensed on 10 August 1982. All requirements then existing for licensing were satisfied and the procedures used by the ERCB were consistent with those used in licensing many thousands of wells during the same general time period.

Policies then in use by the ERCB did not routinely attach special conditions to the licences of wells which might encounter substantial volumes of H_2S and none were attached to the licence for the 13-12 well. It did require an estimate by Amoco of the maximum potential release rate. Because of the estimated relatively low H_2S release rate and the relative remoteness of the well from population centres, the existing ERCB policy did not require a site-specific emergency response plan. One possible deficiency in ERCB staff procedure was that it apparently accepted an estimated maximum potential H_2S release rate from Amoco without adequately checking its validity. Evidence indicated that the original estimate was substantially less than the actual flow rate.

While the licensing procedures were consistent with then existing requirements and policies, the experiences gained as a result of the blowout and the subsequent inquiry have satisfied the Panel that the regulations and policies did not adequately recognize the critical nature of the operation given the high volume of H_2S which could be released if a sour gas blowout were to occur. As indicated in its Phase 2 report, the Panel believes there is a need for special licensing requirements for certain critical sour wells. These requirements include:

(a) a site-specific emergency response plan which satisfies the ERCB that, in the event of a blowout, the public would be adequately protected. The plan should be based on a realistic H_2S release rate and an improved method is needed for calculating the maximum potential release rate prior to the licensing of a critical well,

(b) the ERCB should require a general description of the drilling plan and satisfy itself prior to the issuance of a licence that the equipment, mud system, and other drilling details are satisfactory, and that possible over or underpressured zones and other problems are provided for,

(c) the ERCB should be satisfied with the qualifications and experience of the drilling supervisors. During critical periods, no supervisor should be responsible for key decisions for a period longer than 12 consecutive hours,

(d) service personnel and drilling crews should have appropriate experience and be adequate in number,

(e) properly qualified safety personnel and up-to-date safety equipment should be on the site during critical operations,

(f) the BOP equipment should be inspected in detail by the ERCB prior to critical operations, and questions such as the need for shear rams, the proposed location of the master control panel, and the correct configuration of the BOP stack should be addressed, and

(g) intermediate casing should normally be set above the critical zone.

10.2.2 Rig Inspections

The Nabors rig was inspected by ERCB staff on the 13-12 well site on 18 August 1982. The inspection was in accordance with established policies and the rig was found to be satisfactory. The Panel is satisfied in this regard but believes that critical wells should have a greater than normal inspection frequency and that the inspections should be very detailed. These should be conducted both by staff of the operating company and the ERCB and should be fully documented. In particular, a thorough inspection should take place just prior to commencement of drilling in the critical zone. This matter is discussed in the Phase 2 report.

10.2.3 Drilling Operations in the Critical Zone

At the time the 13-12 well was drilled, there were no special ERCB regulations or requirements respecting drilling operations in the critical zone. It thus follows that there was no contravention of the regulations in this regard. However, having in mind the circumstances which led to the blowout, as described in detail in section 5, the Panel believes the ERCB should give consideration to the need for special requirements to apply to critical sour wells. The requirements to be considered should emphasize the need for particularly cautious and safe practices to be applied at all times when drilling in the critical zone at such wells. They would be in addition to the increased and thorough inspections referred to in the above section.

The type of requirements that the Panel believes the ERCB should give consideration to are as follows:

(a) the need for more detailed documentation respecting checks of the mud system and other key equipment, and counter-signing of such reports by the senior supervisors for both the oil company and the drilling contractor,

(b) the need for more detailed documentation of blowout prevention and safety drills to ensure that such drills are carried out regularly and in an effective manner,

(c) the possibility of increased contacts with the field offices of the ERCB and of an increased role for the ERCB staff, and

(d) the possible need for stronger action by the ERCB when regulations are not strictly adhered to.

The Panel recognizes that the above type of increased control might be difficult to implement on a province-wide basis and would require increased staff on the part of the ERCB. It believes, however, that the potential impacts of a blowout at certain critical sour wells is so great that rather extreme measures must at least be considered.

10.3 Operations to Regain Control

10.3.1 Immediately Following the Blowout

The ERCB was informed of the 13-12 blowout within 2 hours of its occurrence and immediately informed the appropriate Government departments. It took steps to ensure that the site was secured from the public and that initial activities of Government departments were properly co-ordinated.

Although the actions of the ERCB were largely adequate during the initial period, the "one-window" process would have been more effective if a plan had been in place ahead of time which specifically set out responsibilities of the Government departments and identified those to be contacted. Additionally, a more realistic estimate of H_2S concentrations and gas flow rate at the outset would have allowed a better-informed assessment of the safety risks to the public involved, and the best follow-up actions respecting well control, air monitoring, and the need for more immediate actions by public health agencies and other Government departments. The problem of estimating emission rates is addressed in the Phase 2 report, and the current requirements are identified in a Draft Interim Directive issued concurrently with the Phase 2 report and included in it as an appendix.

10.3.2 Well Control Alternatives

10.3.2.1 Consideration of Major Options

The ERCB was aware of and concurred with on-going decisions by Amoco not to intentionally ignite the well and/or not to proceed with the actual drilling of a relief well, although a drilling site was prepared and a rig was placed on standby.

The Panel is generally satisfied that those decisions were reasonable, particularly during the initial period and given the general view that top-hole control of the well consistently seemed to be only a few days away. However, it believes that the ERCB's involvement in these decisions should have been clearer and more formalized. Additionally, the reasons for the decision should have been documented and made known to the public. As the duration of the blowout became more extended, increased consideration should have been given to the other alternatives, particularly igniting the well. The on-going impact of the H_2S emissions on the public while the well was not burning should have been a major consideration in making the decisions not to ignite the well. It is not certain from the evidence that this was the case, and a system should be devised to ensure that it would be in the event of future similar occurrences.

10.3.2.2 Alternative Top-Hole Control Plans

A series of plans for top-hole control of the well was developed and utilized by Amoco. The ERCB was continuously aware of these plans and gave its on-going "approval" to them. The Panel believes that this aspect of the ERCB's involvement was reasonable. However, in future instances, the ERCB should be more actively involved and its decisions on proposed actions more formalized and better documented. This would ensure that accurate, up-to-date information respecting well-control operations could be made available to the public.

10.3.3 Co-ordination Among Government Departments and Agencies

The ERCB played the major role in co-ordinating on-site activities insofar as government involvement was concerned. This appeared to be carried out effectively. The matter of workers' safety was handled independently by OH&S. The Panel sees nothing wrong with that approach, but believes that an overall emergency control plan is needed which clearly spells out the responsibilities of the various Government departments and agencies.

10.3.4 Environmental Impacts

These matters relate to control operations in that the period over which they occur and the type of pollutants can be affected in a major way by decisions respecting well control. For example, the ignition of the 13-12 well would have changed the major air pollutant from H_2S to SO_2 and would have eliminated most of the condensate which was being deposited near the well.

The ERCB co-ordinated efforts with AE and AFS to ensure that containment dikes for condensate were constructed. These efforts were reasonably successful and the Panel is satisfied that the ERCB's co-ordinating functions were useful.

10.4 Effect on the Public

10.4.1 Health Standards and Evacuation Policy

These matters are discussed in detail in section 7, but because of their importance, they are reviewed here in terms of the adequacy of ERCB's involvement. In doing so, it should be noted that the ERCB does not have legislative responsibility for these matters.

The Panel believes there is a strong need for a clear statement of health standards so that in future, the ERCB, which is usually the first government organization involved, can initiate actions to protect the public during the first hours of a blowout and to ensure that public health officials are fully informed respecting well emissions.

10.4.2 Monitoring of Emissions

Monitoring is discussed in section 7 and again, the ERCB does not have direct responsibility. Nevertheless, there is an additional need for the licensee of a well to have a site-specific emergency response plan to be in place so that the ERCB can ensure that the matter of emission monitoring is initiated promptly.

10.4.3 Communications With the Public

This matter is dealt with in section 9 of the report. As indicated there, the Panel believes that this area was not adequately handled during the 13-12 episode by all parties, including the ERCB. There is a need to formulate a communications plan of action which could be implemented during serious blowout episodes and which would inform the public as to what is taking place at the site, existing health standards, the monitoring program, and essentially all aspects of the incident.

10.4.4 Co-ordination of Activities of Government Departments

As indicated previously in section 9 of the report, co-ordination of most aspects of the 13-12 blowout was reasonably handled. However, there were a number of matters where confusion was apparent at least to the public, and where conflicting decisions could have been made. The Panel believes an overall response plan is needed which clearly spells out responsibilities of the Government departments and agencies and ensures maximum co-ordination of all activities.

10.5 Summary of Panel's Views

The Panel is satisfied that the actions of the ERCB prior to, during, and following the blowout were in accordance with the existing regulations and policies. It further believes that most of the regulations and policies are adequate for the large majority of wells drilled in Alberta, but is concerned that they do not adequately recognize the potential consequences of a blowout at a limited number of "critical" sour wells which require extra precautions prior to licensing. These precautions would relate to:

(a) the detailed drilling program,

(b) drilling and blowout prevention,

(c) training and experience of the supervisors and crew,

(d) availability of safety equipment and personnel,

(e) frequency and detail of inspections, and

(f) possible need for special reporting and other requirements while drilling in the critical zone, and for stronger action by the ERCB when such regulations are not strictly adhered to.

There is also a need for a site-specific emergency response plan detailing, among other things, means of communicating with the public in the event of a blowout.

The role of the ERCB with respect to co-ordinating on-site activities with other Government departments and agencies was fully adequate. However, communications with residents in the area and the general public was not at all adequate. In addition to the site-specific plan, efforts are necessary to clearly establish responsibilities of various Government departments and agencies in emergency situations such as the 13-12 blowout. A communications plan is also needed.

10.6 Recommendations

The Panel makes the following recommendations, all of which relate to the role of the ERCB in dealing with blowouts.

1 The ERCB, with appropriate input from industry, the public, and other Government departments, should define wells which are "critical" in terms of avoiding possible blowouts and establish special conditions that must be satisfied by an operator before these wells can be drilled. The ERCB should advise other Government agencies of all licences issued for critical wells.

2 The ERCB and other involved Government departments should establish a plan for their involvement in future emergencies such as the 13-12 well. The plan should include, among other matters, details regarding the responsibilities of various parties, standards for notification and evacuation, and plans for communication with the public and the media. Care should be taken that appropriate municipal officials are aware of the plan.

3 Special efforts should be made to more accurately estimate the potential H_2S release rate for a critical sour well.

The recommendations have already been totally or partially implemented, as a result of the Phase 2 report.

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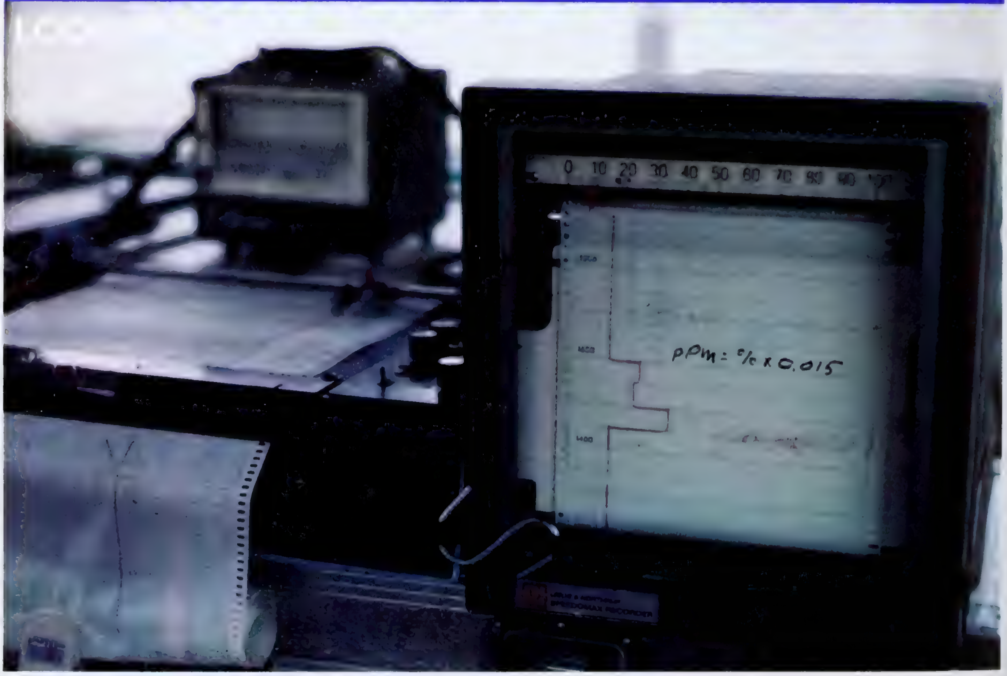


Typical air monitor and print-out equipment.

Photo courtesy Alberta Environment

11 ADEQUACY OF THE GOVERNMENT DEPARTMENTS' RESPONSES FOLLOWING THE BLOWOUT, AND THEIR REGULATIONS, POLICY, AND PROCEDURE

11.1 Introduction

This section deals with the responses by the various Government departments to the blowout at the 13-12 well and assesses whether existing regulations, policy, and procedure were adequate to handle the situation. As was the case in dealing with the ERCB responses in section 10, the Panel will address the following three areas:

(a) drilling operations,
(b) operations to regain control, and
(c) impact on the public.

11.2 Drilling Operations

The involvement of Government departments before or during drilling operations at the 13-12 well was minimal. AFS granted a surface lease to Amoco in February 1982 to drill the 13-12 well. The surface location of the well had been moved away from the Pembina River at the direction of AFS due to environmental concerns. The move of the surface location and Amoco's interpretation of the subsurface geology necessitated the directional drilling of the hole, but given the blowout that occurred, it was fortunate that the surface location was not as originally intended.

The regulation of workers' health and safety during drilling operations was the responsibility of OH&S, who placed the onus on Amoco for the health and safety of both their employees and their contractors. There is no evidence that regulations pertaining to workers' safety were seriously inadequate for normal drilling operations or that they were not adhered to. One exception relates to the number of breathing apparatuses which must be kept at a rig site. The Panel believes the existing regulation, even though it was amended 1 September 1984, may not be adequate and that appropriate masks should be available for each worker on the site and not just the operating crew.

Enforcement of regulations of the various Government departments results in only limited visits to drill sites. The Panel believes that critical sour wells should be inspected more frequently than other wells, not only by the ERCB, but by other Government departments. This is because accidents to workers or the existence of faulty boilers or electrical systems could lead to a blowout or complicate actions to control one in the early stages. For the same reason, workers' safety requirements for sour gas wells should be more stringent than for wells in general.

The Panel believes that OH&S should undertake a review of these matters and should involve other Government departments, the industry, and the public. The Panel believes that some aspects of the review might be effectively accomplished by a series of workshops.

11.3 Operations to Regain Control

Co-ordination of most on-site matters of relevance to Government departments was handled by the ERCB. No serious deficiencies existed in this regard. Necessary approvals for tree clearing, road construction, and stream crossings were handled expeditiously and in a responsible manner by AFS.

Several Government departments were interested in and apparently somewhat involved respecting the decisions not to intentionally ignite the well or to proceed with a relief well. As mentioned previously in this report, the Panel believes the ERCB's role in this matter might have been more formalized. It also believes the involvement of other Government departments should have been better co-ordinated. For example, the changing status of ground-level H_2S concentrations in the area and the number of telephone complaints were not systematically communicated to the appropriate agencies and departments.

OH&S was aware of the blowout within a day of its occurrence and had continued involvement throughout the episode, but its highly qualified occupational health staff were not brought to bear until after the accident involving fatalities a month later. Although evidence suggests that its role was more responsive than pro-active, it was somewhat aware, through its safety inspector, of the safety equipment and procedures being used and was involved in planning meetings. Prior to the accident, OH&S allowed Amoco to use the demand type respirators (non-positive pressure), and subsequently ordered the use of pressure demand masks (positive pressure). The Panel believes that OH&S should reconsider its position and perhaps play a more pro-active role when serious emergency situations such as the 13-12 blowout exist. In such instances, OH&S should consider the advisability of assigning a senior specialist on a qualified full-time basis to the control operations phase to ensure that the safety equipment and procedures are fully adequate.

Securing the blowout site against access by the public was effectively carried out, although there were apparently one or two minor problems likely caused by insufficient co-ordination and communication among involved parties.

AFS took action throughout the blowout to ensure that trees were removed in the immediate area of the well site so that the fire hazard would be lessened. Additionally, AFS and AE, along with the ERCB, required actions to minimize environmental impact. All of these activities were reasonably successful.

The Panel's review of the actions of various Government departments during the well-control phase reveals a number of matters where roles and responsibilities may not have been clear. The Panel believes that an overall plan is required which, among other things, should clearly spell out the responsibilities of Government departments and agencies.

11.4 Effect on the Public

11.4.1 Standards and Evacuation

ADS, AE, SS&CH, the PBOH, along with the ERCB and Amoco, all played a role in setting or interpreting standards, notifying residents in the area, and establishing evacuation criteria. Although each of these groups had the interest of the public in mind and took actions which they considered appropriate, there appeared to be lack of an effective co-ordination system and a lack of systematic communication with the public. These short-comings contributed substantially to the concerns and anxieties of the public.

The Panel is satisfied that the actions taken in the 13-12 incident were generally adequate, although not necessarily well co-ordinated, and that, except for very sensitive individuals, residents were not left in unacceptably hazardous situations due to lack of action by Government departments or others. The situation with respect to very sensitive people is not clear, and as indicated in section 7 the Panel believes that appropriate standards need to be developed. The Lodgepole experience should assist in that endeavour. There is a need for a clear statement, prior to the time of an emergency, respecting appropriate standards and evacuation criteria. These should be part of an overall emergency plan and also should be addressed in site-specific emergency response plans for critical sour wells.

The overall plans should also put in place a system to provide individuals, doctors, and hospitals with assistance and advice respecting the standards.

11.4.2 Monitoring

AE played a lead role in terms of monitoring of the general area to determine ambient concentration levels of H_2S and SO_2. As indicated in section 7, the Panel is generally satisfied that the monitoring was adequate. With respect to the role of AE, it believes co-ordination of the monitoring might have been improved if a control centre had been set up, probably in Drayton Valley, to receive complaints and to dispatch the units. Also, although AE was commended by many local residents for its helpful attitude, the results of monitoring should have been made more readily available to all residents of the area.

AE made several recommendations which related to monitoring. One is that it be given full control of off-site monitoring along with responsibilities to ensure it is adequately carried out. Another is that all available information which might assist in estimating the H_2S release rate be provided to AE at the outset of any sour gas blowout. The Panel believes both of these recommendations are sound and recommends that they be embodied in on-going plans for handling sour gas emergencies.

AE also recommended a review of industry's capability to do extensive monitoring in the event of serious mishaps. The Panel believes that knowledge of this nature on an on-going basis would assist in planning and suggests that the ERCB and AE jointly make such a review.

11.4.3 Communication

As is noted in section 9, which deals with communication in some detail, there was a general inadequacy in this respect. This was true of the Government departments as well as other involved parties.

There was general agreement among the participants during the inquiry that better planning, co-ordination, and communication were necessary and, indeed, one of the recommendations of AE dealt specifically with improved communication with the public. The Panel agrees that this is a very important aspect of dealing with the public and believes a general communication plan is necessary in the event of future emergencies.

11.4.4 Co-ordination

In dealing with the public, co-ordination among Government departments was not well organized. SS&CH is responsible for determining possible health effects. Its process of accessing information from AE, the ERCB, and others, and initiating appropriate action, including advice to the public, was less than adequate. There was no single government telephone number which could be reached and where one would be given a clear statement regarding health standards, monitoring results, or other matters which the Government departments had responsibilities for. Partly as a result, many of the public relied on information from various sources including the media, visits to medical doctors, over-the-fence personal discussions, or casual comments on the street. This situation contributed to the level of concern and anxiety on the part of the public and to some extent may have been alleviated if government authorities had been better co-ordinated and taken a more prominent role in providing information to the public.

This matter must be addressed in a government emergency response plan.

11.4.5 Data Collection and Research Program

There were suggestions at the inquiry that protocols be put in place so that if a similar situation develops in future, data could be gathered from the outset and research could be conducted to increase the knowledge of impacts of H_2S and SO_2 on humans. SS&CH commissioned Dr. Love to assess the feasibility of site-specific work towards this objective following the blowout, but he determined that a meaningful study was not feasible.

Several participants recommended that the government initiate research into the effect on health of exposure to long-term low-level H_2S concentrations. The Panel defines "long-term" to be a period of about a week or longer. The Lodgepole incident demonstrated that concentrations as low as 0.1 ppm for relatively short durations can apparently result in reactions by sensitive persons. The Panel understands that the Alberta Environmental Centre has been pursuing a major research effort in this area for the last 3 years. The PBOH proposed other research into the health effects of long-term low-level exposure to H_2S, but it was decided to wait until the inquiry had been held. As set out in the section 7 recommendations, the Panel believes the possibility of this research should be considered.

AE recommended that steps be taken to determine the detailed composition of all gases which could be emitted from oil and gas pools in the province. The Panel believes there is a need to understand more fully the composition of potential emissions and recommends that the ERCB initiate a study of the matter.

During the period of the blowout, AA visited the area, responded to questions from the public, and had on-going communications with District Agriculturists and veterinarians in the area. On-going research is also taking place. All of these actions were useful and the Panel endorses them. However, it believes they would be more effective if AA took a more pro-active role and publicized to a greater extent its availability to advise and assist the rural population. Plans should be put in place now, so that agricultural information can be readily obtained and evaluated in the event of future emergencies.

11.5 Summary of Panel's Views

The involvement of Government departments following the blowout of the 13-12 well was not altogether adequate. This may have been as a result of a failure to recognize at an early date the seriousness of the situation and to alter their approach accordingly. This was an apparent problem for the ERCB and Amoco as well.

Co-ordination respecting on-site matters during the blowout was good and the orders and approvals necessary to secure the site and proceed with capping operations were given in an efficient manner. The Government departments' role respecting environmental matters was adequate, however, responsibilities of the various departments should be clearly spelled out.

Worker-safety problems developed during control operations and there is a need for more effective planning for the handling of such matters for critical sour wells. This might be assisted through a series of safety workshops organized by OH&S, and by appropriately trained personnel properly conducting inspections.

During the blowout, several Government departments were reviewing and assessing possible public health consequences through interdepartmental committees but did not take public action because they believed that the concentration of pollutants being experienced by most people were not injurious. The Panel believes they underestimated certain effects as described in section 7.2.1. This may account for a lack of communication with the public on these matters and this led to confusion and concern. The matter of handling human health concerns, including evacuation criteria, is an important topic that must be addressed in an overall plan for the handling of sour gas releases.

11.6 Recommendations

The Panel makes the following recommendations respecting the role of Government departments in sour gas blowouts.

1 A government emergency response plan should be put in place for dealing with sour gas releases in the province. Such a plan has been prepared by ADS on an interim basis and will be reviewed in light of this report, comments from the public, and other involved parties. It should be maintained on a current basis. The final plan should address all significant matters relevant to serious sour gas releases and in particular the following:

   (a) the responsibilities and authorities of various departments and agencies,

   (b) the need for a control and communication centre,

   (c) procedures to obtain the best possible estimates of gas flow and composition data,

   (d) the availability of suitable equipment for monitoring,

   (e) ways in which to make communications with the public and media more effective,

   (f) standards, notification, and evacuation criteria and procedures,

(g) the decision process with respect to possible ignition of wild wells,

(h) the collection of data for health research purposes, and

(i) impact of sour gas on animals and crops and ways of better advising rural people respecting these matters.

The public should have the opportunity for input to the plan and should be made aware of its existence when it is in place.

2 OH&S should review its procedures and regulations respecting the suitability and number of breathing apparatuses, the training of workers in their use, review procedures for dealing with workers' health and safety matters for sour wells, and develop a program of direct involvement by senior OH&S staff to be implemented in the event of a blowout. This might be done through a series of workshops.

3 The PBOH should review existing H_2S exposure standards, particularly as they relate to sensitive individuals, in light of experience gained from the Lodgepole blowout.

12

Lodgepole Inquiry Panel members.

Photo credit: G. Brosinsky, ERCB

12 FINDINGS AND RECOMMENDATIONS

12.1 Introduction

In the foregoing sections, the Panel has considered the major issues identified in the inquiry's terms of reference. The purpose of this section is to summarize the Panel's findings and to provide a consolidation of the recommendations contained in each of the sections.

12.2 The Cause of the Blowout and the Adequacy of Amoco's Actions

12.2.1 Findings

1 The 13-12 well blew out of control on 17 October 1982 because a series of kicks occurred during coring operations and were not controlled.

2 The kicks occurred primarily because drilling practices during the taking of cores No. 2 and 3 were deficient and, when combined with the marginal density of the drilling mud, permitted the entry of reservoir fluids into the wellbore.

3 The kicks were not controlled because:

(a) the drilling crew did not immediately recognize the problem and did not immediately carry out prescribed kick-control procedures,

(b) several pieces of vital equipment either did not function properly or were not completely operational, including:

(i) the degasser,
(ii) casing pressure instruments,
(iii) travelling block hook and latch, and
(iv) drill pipe, and

(c) sufficient mixed and conditioned mud was not available during kick-control procedures.

4 Amoco applied reasonable judgement in approving the degasser installed on the Nabors rig, and to a lesser extent, in selecting the type of drill pipe to drill the well, even though with hindsight each turned out to be an unfortunate choice.

5 Amoco's actions were not satisfactory with respect to:

(a) drilling practices during coring operations (cores No. 2 and 3),

(b) prompt implementation of standard kick-control procedures,

(c) ensuring adequate drilling mud was available at all times, and

(d) maintaining equipment in satisfactory condition (casing pressure instruments and possibly mud volume indicators).

6 Drilling operations should always be conducted with caution, with full awareness of potential events, and a preparedness to meet unexpected problems. That requirement is particularly important for wells which may encounter sour gas and especially while drilling in critical zones.

7 Amoco's drilling operations in the critical zone did not display the necessary degree of caution. Moreover, when unexpected problems developed, the company was not fully prepared to meet them. Having regard for its previous blowout at the nearby 7-10 well, just 5 years earlier, the Panel would have expected that Amoco would have applied extreme caution in planning and drilling the 13-12 well.

8 The major deficiencies identified in the 13-12 blowout relate to the "human factor" that received so much attention at the Phase 2 hearing.

12.2.2 Recommendations

1 The following types of equipment should be examined for design, capacity, and operational problems to ensure that they are adequate for worst-case conditions:

(a) degasser,
(b) casing pressure instruments,
(c) travelling block hook latch,
(d) kelly hose,
(e) blowout preventers, and
(f) equipment for anchoring drill pipe.

2 The BPRC should examine the impact of H_2S, and how to avoid those impacts on:

(a) drill pipe,
(b) external BOP components, and
(c) BOP master controls.

3 The industry and ERCB should take any action necessary to ensure that drilling operations are carried out in a cautious manner, particularly in the critical zone of critical sour wells. Special procedures should be developed, documented, and used for operations in the critical zone. These would include detailed instructions respecting tripping in, tripping out, coring, testing, and other operations where particular care is required.

4 Standard kick-control procedures should be reviewed to determine whether they allow for situations where equipment failures or other unexpected events occur during control operations.

5 The adequacy of the current training programs for drilling personnel should be reviewed and, in particular, consideration should be given to ensuring

that they are effective in ensuring crew familiarity with kick recognition and control.

6 Consideration should be given to the need to have special expertise available while operations are being conducted in the critical zone of critical sour wells.

7 The ERCB should review its inspection system and, in particular, it should conduct special inspections of critical sour wells immediately prior to entry of the critical zone and while drilling in it, to ensure that operations are being conducted in a cautious manner and consistent with proper procedures.

8 Mud system design and operation should be reviewed respecting density, system capacity, back-up supply, scavengers, and impact of H_2S on mud and the ability to pretreat and recondition it.

9 OH&S should consider amending its regulations to ensure that breathing apparatuses are available for all individuals that may be at a rig, including extra people called in for an emergency.

12.3 Well-Control Activities and the Adequacy of Actions by Amoco and Others

12.3.1 Findings

1 Amoco's general emergency response plan was satisfactory for well-control operations because it brought together those persons who had knowledge and authority to implement necessary actions.

2 With the exception of well control Plan A, which did not have significant impact, the well-control plans proposed by Amoco, and approved by the ERCB, were satisfactory even though actual events proved several of them to be unsuccessful.

3 Regaining control of the well required 67 days because

(a) the well had a particularly high flow rate and high H_2S and condensate content,

(b) weather conditions were frequently unfavourable and prevented work on the well for more than 10 days, when the control plan in effect at that time was based on capping the well when it was not on fire,

(c) the normal industry safety procedures and equipment proved insufficient to cope with the magnitude and type of emissions from the well, and

(d) the final and successful control plan for capping the well while on fire required 21 days for preparation of the site and equipment, and because of delay due to weather conditions before it could be completed.

4 The decision by Amoco and the ERCB not to drill a relief well, as a means of regaining control of the 13-12 well, was reasonable.

5 The decision by Amoco and the ERCB, during the initial period, not to try and cap the well while on fire (even though this was the final and successful plan) was reasonable at the time, having regard for the expectations of successfully capping the well while not on fire and the serious risks inherent in an "on-fire" control process.

6 Decisions on well-control plan options were deficient in that they did not adequately take into account the effects the emissions were having on the public, or the seriousness of the public's concerns.

7 Amoco's actions, except for the relatively minor problem of the pipe stripper respecting control Plan A, were adequate with respect to regaining control of the well. Amoco applied diligence, technical expertise, and all the necessary resources for regaining control as quickly as possible.

8 The ERCB applied diligence and technical expertise regarding control of the well. However, it did not adequately take into account the impacts on, and concerns of, the public in reviewing the suitability of the various control operations proposed by Amoco.

9 OH&S was not sufficiently involved in the safety procedures during the initial well-capping operations.

10 Safety measures were not successful on 16 November during attempts to cap the well while it was not on fire and the deaths of two workers occurred. Safety procedures to be used in emergency situations require review.

12.3.2 Recommendations

1 The ERCB and the involved operator should make a serious effort at the outset of any blowout to ensure that the flow rate and other characteristics are estimated as accurately as possible, and that the estimates and the expected weather conditions are properly recognized in planning for control of the well.

2 The ERCB should formalize, to a greater extent, its involvement in decisions related to intentionally igniting blowouts and the possible drilling of relief wells. A process should be developed that would ensure that public concerns are properly considered in making these decisions, and the reasons for the decisions are communicated to the public.

3 OH&S should give consideration to the establishment of a committee to be concerned with protect-

ing workers in toxic gas environments such as would result from episodes like the 13-12 blowout. Such a committee might be composed of experts on safety and rescue drawn from OH&S, the petroleum industry, the ERCB, and the Calgary and Edmonton fire departments. These individuals, or a team which they could assemble, could be readily available to act as advisers or participants in the management of the safety aspects of particularly dangerous situations in the petroleum industry. With respect to the prevention of serious accidents, they could assist in reviewing current and future safety and rescue practices and safety educational programs.

4 OH&S should give consideration to the development of an adequate, possibly compulsory, training program for workers who might encounter H_2S or other toxic gases in substantial amounts. This training would be needed prior to their involvement at a well site or other potentially dangerous locations. This training should emphasize practical matters such as familiarization with and the wearing of a self-contained breathing apparatus. Through such a program, workers who are physically or psychologically unsuitable for work in such hazardous environments, or while wearing masks, would likely be identified.

5 The ERCB should investigate the availability and limitations of blowout insurance. The Panel understands that the matter of insurance is being looked at by the ERCB as a result of the Phase 2 report.

6 The ERCB should consider how the experience and expertise needed to control a blowout would always be available when required, even by a small organization.

7 OH&S should pursue the development of clearly distinguishable names for all types of masks to be used in the presence of various concentrations of H_2S.

8 Consideration should be given by industry and the ERCB to the development of a workshop or seminar to consider technical matters related to the control of wild wells.

12.4 Hazard to Human Health

12.4.1 Findings

1 While there was no scientific basis for the Panel to make any definitive conclusions regarding effects of well emissions on human health, it is satisfied that a substantial number of people experienced at least short-term health effects such as headache, eye irritation, upper respiratory tract symptoms (sore throat, nasal irritation, and nosebleeds in children), and lower respiratory tract symptoms (pain on deep inhalation and some shortness of breath). Persons with respiratory problems appeared to be especially affected. Several of the PASGEC witnesses referred to similar symptoms of illness in both people and livestock.

2 Government departments and the ERCB established and applied a set of H_2S exposure limits that were designed to protect human health.

3 The H_2S exposure limits, established for persons more susceptible to the emissions, were generally criticized by the public as being inadequate.

4 Anecdotal evidence raises questions about the H_2S exposure limit, particularly for sensitive persons.

5 Under the direction of AE, H_2S concentrations downwind from the well were monitored by a combination of mobile and stationary monitors to ensure that if concentrations exceeded the exposure limits, the residents would be advised to vacate the area.

6 On six occasions, when H_2S concentrations near residences reached 15 ppm, residents temporarily left the area. Additionally, Amoco offered assistance to residents to leave the area if the emissions were causing problems, and 28 individuals plus 4 families moved temporarily on that basis.

7 During the 26 days that the well was not on fire, H_2S concentrations at, or near, residences exceeded 10 ppm for about 31 hours in total, and 5 ppm for 61 hours. The stationary monitors located at Lodgepole, Cynthia, and Drayton Valley recorded concentrations less than 1 ppm for 87, 95, and 96 per cent, respectively, of the total hours monitored. In Edmonton, the maximum concentration recorded was 0.5 ppm, and the overall concentrations were about one-tenth of those experienced by the three communities near the well.

8 On 23 November, H_2S concentrations at Cynthia approached the evacuation limit and residents were advised to be prepared to leave. The concentrations subsequently declined and the evacuation alert was cancelled. That incident created considerable controversy and some participants questioned whether the standards had been followed. After careful examination of the actual monitoring data, the Panel found that the standards had been followed.

9 The Panel is satisfied that the air monitoring program was comprehensive and, with the exception of sensitive persons residing in rural areas, provided

sufficient information to apply the established exposure limits. The exception was due to the special standard for sensitive persons, which relied on a lower level of exposure for 5 to 6 hours. Since concentrations in the rural areas were monitored by mobile units, it was not possible to determine whether that exposure limit had been satisfied.

10 While the monitoring was effective, the communication of the plan and its results to the local people was quite inadequate. Residents were not advised about the program, and were not always able to obtain answers to their inquiries about monitoring results.

11 While the well was on fire, the H_2S was converted to SO_2. Because of the intense fire, the emission plume had substantial rise, and its dispersion was effective. Throughout the blowout period, SO_2 concentrations were substantially below the related ambient air quality standards.

12.4.2 Recommendations

1 The PBOH should reconsider its H_2S exposure limits in light of the Lodgepole evidence and, in particular, for "sensitive individuals".

2 Information should be obtained by the PBOH on the biological effects of extended intermittent and continuous exposure to moderate and low-level concentrations of H_2S, such as were experienced by residents and animals during the Lodgepole blowout. This could be obtained by modern research techniques.

3 AE, the ERCB, and representatives from industry and the public should develop a comprehensive centrally dispatched air monitoring plan that could be implemented immediately when needed.

4 AE and the ERCB should arrange for a comparison and analysis of actual H_2S concentrations obtained by monitors and the predicted concentrations from dispersion modelling, with the objective of improving the latter capability.

5 Further consideration should be given by the PBOH and other medical bodies to whether useful information could be obtained from a review of actual medical experience during the blowout, and to consider whether better measures can be implemented to determine the effects of emissions from other blowouts which may occur in the future.

6 Methods of providing remote rural residents with Drager units and possibly crush ampoules, and training in their use, should be addressed in site-specific emergency response plans.

7 The ERCB should attempt to identify all of the gaseous contaminants, in addition to H_2S and SO_2, which could be produced by a sour gas well, since other components could also have biological significance. This type of physical chemical analysis could be carried out on material safely obtained from an existing well or wells.

12.5 Impact on the Environment

12.5.1 Findings

1 During the 67 days the well was out of control, there was a daily emission of 150 to 450 tonnes of sulphur and 300 to 1100 m^3 of condensate. For the 26 days the well was not on fire, the condensate fell on the area immediately surrounding the well site and had an impact similar to an oil spill. When the well was ignited, the condensate was combusted in the extremely intense fire, and the H_2S was converted to SO_2.

2 In the area of some 300 ha immediately surrounding the well, the emissions had major impacts on vegetation and soils, and minor impacts on surface water, groundwater, benthic organisms, mammals, and birds.

3 A program of remedial measures was quickly implemented to minimize these environmental impacts.

4 There is no evidence that the sulphur deposited on the ground in low concentrations, over an area of hundreds to thousands of square kilometres, will have any long-term harmful effects on the soils, vegetation, or bodies of water.

12.5.2 Recommendations

1 AE and other appropriate Government departments should establish a protocol for improved sampling and analysis of soil and vegetation that would provide a means of evaluating impacts of sour gas releases on soils and vegetation if a blowout occurs in future.

2 AFS should co-ordinate long-term monitoring of impacts on the biosphere in the "on-site and immediate" area of the 13-12 well, plus adjoining areas of the blowout, as defined in this report.

3 AA should develop a protocol to enable the gathering of timely and relevant data on agricultural activities if another serious sour gas release occurs.

4 AA should consider conducting an on-going examination of livestock in the general blowout area to determine if effects of long-term exposure to H_2S can be found.

5 The ERCB, the industry, and appropriate Government departments should consider ways of dealing with concerns of the public respecting monetary impacts on the public resulting from sour gas blowouts.

6 The ERCB and AE should arrange a symposium to hear expert views on plume modelling/plume impingement and sulphation ground sampling analysis techniques.

12.6 Communication and Co-ordination

12.6.1 Findings

1 The ERCB and most Government departments agreed that their efforts to communicate information about the blowout to the public and the media were generally unsuccessful.

2 The inadequacies of the communication program were a major reason for the broad concerns and fears of the public.

3 There is a need, in the event of a similar incident, for a comprehensive communications program to be implemented immediately. Furthermore, the communications should be a two-way process to ensure that not only does the public understand the plans and actions of those responsible for regaining control of the well, but that those in charge understand, appreciate, and respond to the concerns of the public.

4 The efforts to ensure that the media were fully informed for it to properly carry out its essential role of keeping the public well informed were not successful. Co-ordination among Government departments and agencies was reasonably efficient, but was not always perceived as such by the public.

5 A plan that clearly sets out the responsibilities of each of the parties was not in place. Additionally, one agency was not formally responsible for overall co-ordination.

12.6.2 Recommendations

1 A model communication program, along the lines suggested in section 9.4, should be developed by appropriate Government departments and agencies with input from the public and industry.

2 The "Peacetime Emergency Operations Plan For a Sour Gas Release", recently issued by ADS, should be reviewed in light of the Panel's recommendations.

3 The establishment of a "command post" organizational structure should be confirmed and implemented for all significant blowouts.

12.7 Adequacy of ERCB's Responses Following the Blowout, and Its Regulations, Policy, and Procedure

12.7.1 Findings

1 The ERCB met all existing requirements in licensing the 13-12 well.

2 The experience gained from the blowout, together with evidence presented at the inquiry, has convinced the Panel that the regulations and policies did not adequately recognize the critical nature of the operation, given the high volume of H_2S which could be released if a blowout were to occur. Accordingly, special licensing requirements are needed for certain critical sour wells.

3 The Nabors 14E rig was inspected by ERCB staff in accordance with established policy, but inspections by both the ERCB and industry should be increased for critical wells such as the 13-12 well.

4 The ERCB did not have any involvement in the operations in the critical zone prior to the blowout, but the Panel questions whether that was appropriate.

5 ERCB actions were generally adequate with respect to control operations, except that it did not fully recognize the effects the emissions were having on the public.

6 Well-control activities, and accuracy of communication with the public, would have been enhanced if a more accurate estimate of the H_2S concentration and gas flow rate had been available at the time of the blowout.

12.7.2 Recommendations

1 The ERCB, with appropriate input from industry, the public, and other Government departments, should identify wells which are "critical" in terms of avoiding possible blowouts and establish special conditions that must be satisfied by an operator before these wells can be drilled. The ERCB should advise other government agencies of all licences issued for critical wells.

2 The ERCB and other involved Government deparments should establish a plan for their involvement in future emergencies such as the 13-12 well. The plan should include, among other matters, details regarding the responsibilities of various parties, standards for notification and evacuation, and plans for communication with the public and the media. Care should be taken that appropriate municipal officials are aware of the plan.

3 Special efforts should be made to more accurately estimate the potential H_2S release rate for a critical sour well.

12.8 Adequacy of The Government Departments' Responses Following the Blowout, and Their Regulations, Policy, and Procedure

12.8.1 Findings

1 Worker-safety problems occurred during the control operation resulting in the deaths of two workers, and excessive exposure to H_2S by several other workers. The related regulations and procedures were found to be inadequate and require modification.

2 H_2S exposure limits were not clearly established, particularly for persons sensitive to H_2S. An appropriate standard needs to be established for sensitive people.

3 In general, Government departments did not exhibit the appropriate concern for the problems being experienced by the public and did not respond effectively to their inquiries.

12.8.2 Recommendations

1 A government emergency response plan should be put in place for dealing with sour gas releases in the province. Such a plan has been prepared by ADS on an interim basis and will be reviewed in light of this report, comments from the public, and other involved parties. It should be maintained on a current basis. The final plan should address all significant matters relevant to serious sour gas releases and in particular the following:

(a) the responsibilities and authorities of various departments and agencies,

(b) the need for a control and communication centre,

(c) procedures to obtain the best possible estimates of gas flow and composition data,

(d) the availability of suitable equipment for monitoring,

(e) ways in which to make communications with the public and media more effective,

(f) standards, notification, and evacuation criteria and procedures,

(g) the decision process with respect to possible ignition of wild wells,

(h) the collection of data for health research purposes, and

(i) impact of sour gas on animals and crops and ways of better advising rural people respecting these matters.

The public should have the opportunity for input to the plan and should be made aware of its existence when it is in place.

2 OH&S should review its procedures and regulations respecting the suitability and number of breathing apparatuses, the training of workers in their use, review procedures for dealing with workers' health and safety matters for sour wells, and develop a program of direct involvement by senior OH&S staff to be implemented in the event of a blowout. This might be done through a series of workshops.

3 The PBOH should review existing H_2S exposure standards, particularly as they relate to sensitive individuals, in light of experience gained from the Lodgepole blowout.

12.9 Summary

The findings indicate that the 13-12 blowout probably could have been avoided, even allowing for equipment failures, had Amoco followed a policy of cautious drilling in the critical zone and been better prepared to deal with unexpected developments. The public was understandably concerned, frightened, and angry about the blowout. Two workers lost their lives and the public experienced widespread unpleasant health effects. While the evidence suggests to the Panel that the actual long-term physical effects were relatively minor, the legacy of the Lodgepole blowout will influence the Alberta energy resource scene for many years. This is a matter that will require special attention by industry, the ERCB, and Government departments. Special efforts must be made by all parties to avoid another occurrence.

The Panel has made many recommendations that, if fully implemented, can significantly reduce the number of sour gas blowouts in Alberta. Special emphasis has been placed on critical sour wells. Several of the recommendations are for a review of drilling equipment, but the primary emphasis has been placed on the need to reduce blowouts caused by human failures. The Panel has reviewed the inquiry reports issued earlier this year for the blowout at the SHELL ET AL UNIACKE G-72 well, off the east coast, and the loss of the Ocean Ranger drill rig. It also has reviewed the previous ERCB report on the blowout of the 7-10 well which occurred in the same area only 5 years prior to the 13-12 blowout. Each of these three reports indicates that a combination of equipment and human factor causes were responsible for the failures. In each case, the relevant inquiry panel either directly or indirectly indicated that the failure probably would not have occurred had appropriate practices been followed, notwithstanding the equipment problems. The conclusions are thus very similar to the Panel's for the 13-12 well.

The question, then, is how can human factor problems be significantly reduced in drilling operations? The Panel believes that the most effective way would be to ensure that personnel:

(a) are well trained,

(b) are conscious of potential problems and ready to deal with them,

(c) are adequately supported by technical assistance,

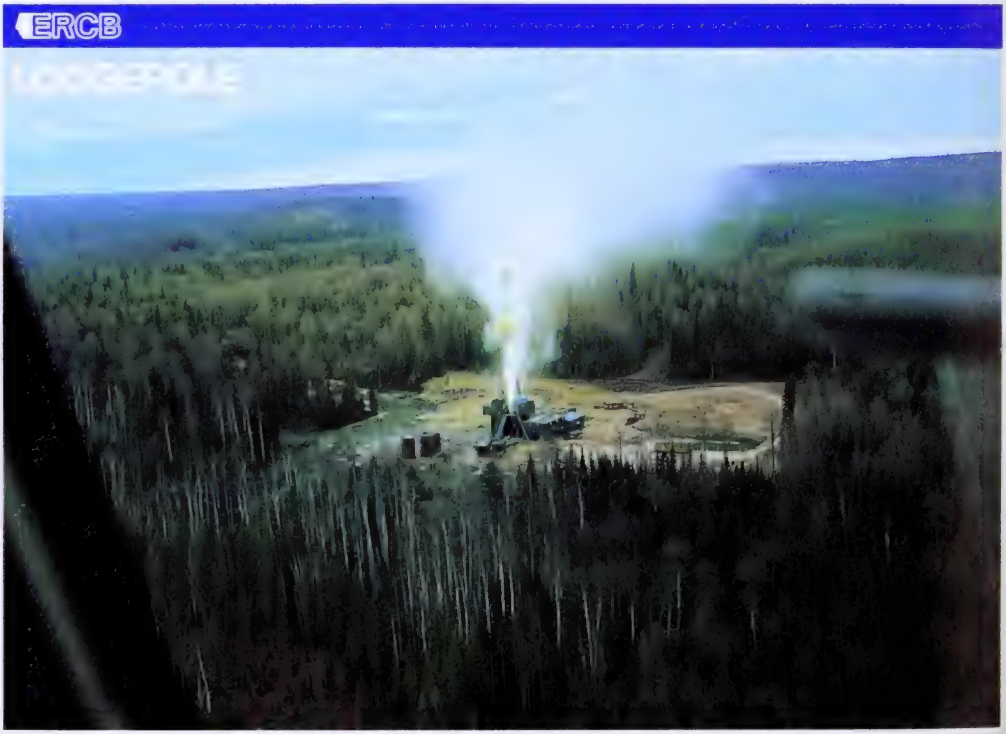
(d) follow a sound and safe drilling plan, and

(e) proceed with operations in a cautious manner, particularly while operating in critical zones.

The primary responsibility for ensuring that these objectives are achieved lies with industry and in particular with the company that has been issued a licence to drill the well.

Several of the Panel's recommendations address these issues. The Panel also believes that the ERCB has a responsibility to test whether these objectives are being achieved, and in that regard believes that its inspection system should be carefully reviewed to determine how it can be strengthened to minimize human factor problems.

13



The 13-12 blowout area against its forest background.

Photo credit: W. Wylie, ERCB

13 SIGNIFICANCE OF INQUIRY RECOMMENDATIONS IN REDUCING THE POTENTIAL FOR BLOWOUTS

One of the primary objectives of the inquiry into the blowout of the 13-12 well was to identify changes in drilling operations that could be made which would significantly reduce the likelihood of future blowouts. A related objective was to evaluate the operations that were carried out to regain control of the well to ascertain whether different procedures should be applied in any future cases. Additional primary objectives included determining the degree to which the blowout affected the public, and identifying measures that could have been taken to reduce these effects during the period the well was out of control. This, in turn, could lead to changes in the procedures used to protect and inform the public so that in future emergencies, the effect on the public might be reduced.

In reviewing all of the evidence presented at the inquiry, and in considering the various submissions made by participants, the Panel has arrived at a number of findings and recommendations as summarized in section 12. The key question remaining is, "Would the adoption and implemention of the Panel's recommendations significantly reduce the likelihood of future blowouts, improve the procedures used to regain control if a blowout should occur, and reduce the effect on the public in the event of a blowout?"

The Panel believes the question can be at least partly answered by comparing actual developments at the 13-12 well with what would have occurred if the Panel's recommendations had been in effect and followed. This comparison, of course, is speculative in nature because of uncertainties about the effect some of the suggested changes would have had in this particular instance. Also, because many of the recommendations require additional work by the BPRC and the ERCB, there may be changes in the future which cannot be identified at this time.

Table 13.1 analyses the situation at the 13-12 well with respect to three separate aspects of the incident.

Part A of the table relates to the drilling phase when the blowout occurred and attempts to determine if the recommendations resulting from this inquiry would have significantly changed any of the causal factors of the blowout.

Part B deals with on-site efforts during the blowout to regain control of the well. It attempts to draw conclusions as to whether the recommended changes would have impacted on these efforts and, in particular, have shortened the duration of the blowout.

Part C deals with public effect aspects of the blowout and speculates as to whether the recommendations arising from the inquiry would have lessened the effect on the public of the 13-12 blowout.

The table identifies those factors which were significant for the 13-12 well with respect to one or more of the three phases, and summarizes changes to requirements which would have been in effect had the recommendations contained in this report been adopted prior to the blowout. It then speculates as to the potential effect of these changes on the actual procedures or practices at the 13-12 well and indicates its views as to the significance of the changes at the particular well.

Part A of the table, Drilling Operations, analyses each of the factors which were identified as contributing to the cause of the blowout in section 5 of this report. The Panel found that the following factors were especially significant in contributing to the kick and subsequent blowout:

(a) drilling procedures in the critical zone,

(b) adequate supply of mud, particularly for operations in the critical zone,

(c) use of H_2S resistant drill pipe,

(d) fully effective drilling equipment including a back-up degasser, and

(e) extraordinary caution by drilling crew during critical zone operations and additional supervisory resources during problem period (human factor).

The Panel has made recommendations respecting each of these factors, most of which relate to special licensing requirements for critical sour wells. The need to satisfy the ERCB with respect to the drilling program, the mud system, the equipment to be used, and the level of experience and training for the supervisors and crew would focus considerably more attention on each of the matters that went wrong at the 13-12 well. The Panel believes that had these recommendations been in effect and complied with during the drilling of the well, the blowout probably would not have occurred.

Part B of the table deals with efforts to regain control of the well. The factors listed are those identified in section 6 of this report as having played an important role in gaining control of the 13-12 well. There were a number of areas where the situation might have been helped; for example, a better sour gas flow estimate may have been available. Also, if the original BOP controls would have been at a remote location, and thereby more protected from the H_2S in the escaping gas, there might have been a greater chance of the success of Plan B, as set out in section 6. Effective safety equipment likely

TABLE 13.1 POSSIBLE CONSEQUENCES OF INQUIRY RECOMMENDATIONS ON LODGEPOLE INCIDENT

Phase of Incident	Particular Factor	Changes to Requirements as a Result of Recommendations	Potential Effect of Changes to Procedures	Significance of Changes to Lodgepole
PART A				
Drilling Operations	Geological Information	Detailed geological information required	Better understanding of rock properties, pressures, and of chances of encountering sour gas	Low
- Blowout	Density of Mud	Detailed pressure information required	Higher mud density used	Medium
	Mud Supply	Detailed information required on mud system and actions if problem occurs	Additional mud capacity and/or supplies allowing more sustained circulation of kick	High
	Drilling Procedures	Following prescribed procedures and employing caution	Greater awareness and caution taken	High
	Degasser	Improve degasser design and/or require back-up degasser or alternative	Allow continuous mud circulation	High
	Drill Pipe	Require use of H_2S resistant drill pipe	Drill pipe would be more resistant to failure	High
	Miscellaneous Equipment – gauges, travelling block, kelly hose	More rigorous inspection to ensure sound maintenance	Better supervision should lead to better assurance of all equipment being 100 per cent operational during critical zone penetration	High
	Human Factor	Improved training, hours of work, working conditions, supervision, and assurance of crew qualifications and experience	Assurance of complete awareness by supervisors, service personnel, and drilling crews of critical zone penetration situation and of required drilling procedures and different actions during kick control	High
PART B				
Regaining Control	Volume of Blow, H_2S and Condensate Content	Detailed information required	Better estimates of flow	Medium
	Site-Specific Emergency Planning	Planning would be in greater detail	More detailed knowledge of rig equipment and capability to implement specific control procedures	Medium
	BOP Equipment	Additional information required	Remote location for master controls	Medium
	Safety Equipment and Procedures	Detailed information required	Better equipment and increased awareness of importance and perhaps avoidance of serious accident	High
	Igniting Well and Drilling of Relief Hole	General plans required and system in place to ensure full awareness of concerns of the public	Somewhat more complete assessment of control options and blowout effects could limit period when well unignited	Low
PART C				
Effect on Public	Site-Specific Emergency Response Plan	Plan would be required	More organized and timely response to protect the public	Medium
	Volume of Blow, H_2S and Condensate Content	Detailed information required	Better estimates of flow, if available, could assist in assessing occupational risks, public health risks, air monitoring programs, and decisions regarding intentional ignition and/or relief hole	High
	Monitoring	General plans required	Earlier monitoring and more detailed coverage	Medium
	Communications	General program established by Government departments and control centre set up	More effective communication by providing public with information on well blowout status, control plans, monitoring, standards, evacuation, etc.	High
	Co-ordination	General program established by Government departments and control centre set up	More effective contact among Government departments and less chance of conflicting statements or directions	Medium

would have enabled Plan C to be successful. Additionally, greater attention would likely have been given to the broad reactions of the public in deciding whether to intentionally ignite the well. While this almost certainly would not have resulted in igniting the well, it may have meant that well control Plan C, which involved extinguishing the well after it had accidentally ignited, might have been rejected and efforts to control the well while on fire might have been initiated sooner.

Part C of Table 13.1 analyses the situation with respect to the effect on the public of the 13-12 blowout. The factors listed in the table are those identified in sections 7, 8, 9, and 10 as having been particularly significant in terms of the effect on the public.

The table indicates that there would have been major changes if the recommendations contained in this report were in effect before the blowout. In particular, there would have been a site-specific emergency response plan and a general sour gas emergency plan in place. These almost certainly would have resulted in a much improved communications approach with the public and the media, and to the establishment of a control centre which would have directed overall operations and handled all information requests and complaints from the public. Since one of the major effects on the public appears to have resulted from uncertainties and related anxieties, most of which stemmed from insufficient information respecting the blowout, control plans, health standards, monitoring, and evacuation criteria, it follows that the changes would likely have improved the public's perception of the situation substantially. They would not, however, have affected the health effects described previously in section 7, except to the extent that the decision to cap the well while on fire may have been made earlier.

In summary, the Panel believes the recommendations contained in this report, and summarized in section 12, would have had a real impact on the event had they been in place prior to the 13-12 blowout and had they been adhered to throughout the planning, drilling, and other phases. In particular, with the changes in the planning and drilling, the blowout would probably have been avoided. However, if it had occurred, there would have been a potential to modestly expedite control operations or at least ensure that the concerns of the public were being properly considered when making decisions respecting control options. Finally, public anxiety and concern would almost certainly have been significantly lessened through an improved and co-ordinated communication program.

The Panel believes that these conclusions respecting the likely significance of the recommendations on the 13-12 incident can be extrapolated into the future for all wells to be drilled in the province. It is satisfied that the recommendations will, if fully implemented, significantly reduce the frequency of blowouts, particularly for critical sour wells.

The key factor lies in their implementation and in overcoming problems caused by human failure. As indicated previously, the Panel believes that can best be achieved by exercising extreme caution while carrying out operations in the critical zone. The Panel urges both industry and the ERCB to take any action necessary to ensure that care and caution become the operating philosophy in drilling critical sour wells.

14

The Blowout Prevention Review Committee (BPRC) seeking ways to prevent another ''Lodgepole''.

Photo credit: G. Brosinsky, ERCB

14 REPORT ON DEVELOPMENTS SINCE THE RELEASE OF THE PHASE 2 REPORT

14.1 Introduction

In April 1984, the Panel issued its Phase 2 report (see Appendix 5). The report included a wide range of recommendations which were categorized by the Panel as to their relative importance. Most of the recommendations related to ERCB responsibilities and it indicated that immediate action would be taken to either implement or examine those recommendations that had the highest priority. The primary purpose of this section is to provide a brief summary of the current status of those activities.

During the last 7 months, many representatives of industry, the ERCB, and where appropriate, the public and Government departments have devoted substantial time and effort to the consideration of the specific issues assigned to them. To illustrate, 45 different people have served in 53 positions of the BPRC or its subcommittees. It is estimated that these persons and others directly involved in BPRC activities to date have contributed 40 man-months of time. An additional 30 man-months is thought necessary to complete the Phase 2 activities.

14.2 Recommendations in the Phase 2 Report

The following lists each of the recommendations contained in the Phase 2 report and provides a brief description of its current status.

1 Establish special controls for selected sour wells that, in case of a blowout, have a potential for emitting large volumes of sour gas – especially if the wells are to be located near residential areas (section 5.1.1)[1].

A Draft Interim Directive was issued by the ERCB in April 1984 (Appendix 5 of Appendix 5) which defined critical sour wells and the site-specific emergency plan, well planning, and supervision that is required. To date, 12 wells have been licensed in accordance with these requirements. Comments on the ID were solicited from industry, government, and the public and these are now being considered.

2 Establish a joint industry/ERCB committee to review ERCB rig inspection procedures (section 3.3.3).

The committee was formed and has developed a large number of recommendations that will result in more effective inspections and increased enforcement. The reporting of inspection results has been expanded to keep industry fully informed and better able to self-regulate. By late November 1984, most of the committee's recommendations had been implemented.

3 Review the availability of blowout insurance and the advantages it may have to ensure adequate funds in case of a blowout (section 5.2.4).

An internal ERCB committee has studied the many variations and refinements of blowout insurance that are available. Representatives of the oil and gas industry and insurance industry have been interviewed to determine current practice. Government agencies in Canada, the United States, and Europe have been contacted to determine what is being done in other jurisdictions. A report is being prepared and will be provided to industry and the public for comment.

4 Develop criteria for igniting a sour gas well in case of blowout (section 5.2.1).

ERCB staff have developed draft criteria based in part on their experience with the emergency plans they presently review and approve for sour wells. These proposed criteria will be discussed with industry, Government departments, and the public.

5 Review safety aspects of sour well drilling, especially with respect to breathable air supply (section 5.3.1).

The matter of worker safety at the rig site is within the jurisdiction of OH&S. The ERCB decided to delay a request to OH&S to initiate the broad study until after the Lodgepole Phase 1 report becomes available. Notwithstanding that decision, OH&S has been kept informed of BPRC activities, and is represented on two BPRC subcommittees (Training and Detection).

6 Establish a committee to review technical and economic issues related to blowout prevention (section 4.2).

The BPRC was established as a joint industry/ERCB committee with provision for participation by representatives of the public and Government departments as appropriate. The assessment and recommendations of the BPRC will be made public and will be subject to review and comment by all interested persons when they become available. Each of the many issues presented to the committee have been considered and an appropriate course of action for each determined as follows:

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[1] Section references refer to the Phase 2 report included in Appendix 5.

(a) Review training requirements (section 5.1.2).

A joint industry/ERCB subcommittee was established which started by defining a hypothetical sour well and then determining the skills and training requirements of the personnel required to plan and drill the well. The training requirements will be compared to what is now available and from this, the deficiencies in present training will be identified.

(b) Review frequency and timing of industry and ERCB rig inspections, and enforcement of requirements (sections 5.1.3 and 5.1.4).

A joint industry/ERCB subcommittee was established which has recommended daily and weekly inspections by drilling rig supervisory personnel, and ERCB inspections keyed to drilling progress. Alternative for enforcement were considered and the suspension of drilling progress, in case of "serious" deficiencies, has been recommended.

(c) Review a large number of equipment-related concerns with particular emphasis on BOP equipment for sour gas drilling (section 5.1.6).

Two joint industry/ERCB subcommittees have been established, one to review the BOP stack and the second to consider associated equipment such as drill pipe and BOP manifolds. Because of the number of problems they faced, both subcommittees have divided into task forces to address specific matters, such as the requirements for drill pipe in sour gas service. All the task forces have initiated their studies and are interacting at the subcommittee level as required.

(d) Review techniques available to monitor for warnings of drilling problems, such as a kick or the presence of H_2S (section 5.1.6).

A joint industry/ERCB subcommittee has been established which has reviewed equipment and procedures presently available to monitor at the surface as well as at the bottom of the well. Limitations in present technology have been identified and areas of potential improvement will be determined.

(e) Consider the merits of developing an Alberta Code of Practice for Drilling (section 5.1.11).

The BPRC has discussed the kind of guidelines that are needed and are not satisfied by the present regulations, company procedure manuals, or industry association manuals. Some tentative concepts have been developed and these will be reviewed and developed further after the Lodgepole Phase 1 report is available.

(f) Consider the need to develop guidelines for winter drilling (section 5.2.1) and mud system design (section 5.1.10).

The BPRC has concluded that these matters and some aspects of well planning (section 5.1.9) should be considered in conjunction with a code of practice that might be developed.

(g) Review the merits of special supervision requirements while drilling sour wells, especially where the sour zone has been penetrated (section 5.1.5).

Since the Draft Interim Directive (item 1) requires increased supervision at critical sour wells, the BPRC decided to defer consideration of this question until it had acquired some experience with those requirements.

(h) Consider the need to improve the availability of information that would assist in learning more about blowouts and their prevention (sections 5.1.7 and 5.1.9).

The BPRC has obtained information on the services that are now available from scientific and technical libraries, commercial information services, Government agencies such as the Alberta Research Council, and the ERCB. These will be compared to the information needed to prevent blowouts generally, and to plan the drilling of a specific well to determine if gaps exist.

(i) Review the merits of having a co-operative pool of equipment that would be needed in case of a blowout (section 5.2.5).

The need and practicability of such a pool is being considered by the BPRC, having regard for previous blowout experiences and experience in the past with similar equipment pools.

(j) Analyse the effect of human factors such as training, health, and hours of work on safety and preventing blowouts (section 5.1.2).

Consideration of this matter by the BPRC has been deferred pending availability of the Lodgepole Phase 1 report.

The Drilling Rig Inspection Committee filed its report with the ERCB in June 1984 and the BPRC has filed two progress reports with the ERCB. All three reports were mailed to participants of the inquiry, and copies are available to the public at the ERCB offices in Calgary.

ISSUED at Calgary, Alberta, on 11 December 1984.

LODGEPOLE BLOWOUT INQUIRY PANEL

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APPENDIX 1 GLOSSARY OF TERMS

alkaline formation water	water originally in place in a formation and containing a high concentration of hydroxyl ions in solution.
ambient	meaning surrounding, or on all sides. Ambient is generally used to describe the condition of a larger body in which the subject of interest is located.
ampoule, crush	a small, gauze wrapped, glass vessel containing liquid lead acetate which, when crushed, permits the lead acetate to impregnate the gauze wrap. In the presence of hydrogen sulphide, the lead acetate will turn various shades of brown depending on the concentration of hydrogen sulphide present.
annular preventer	a large valve, usually installed above the ram blowout preventers, that forms a seal in the annular space between the pipe and wellbore, or if no pipe is present, on the wellbore itself.
annulus	the space between two concentric pieces of pipe or between a pipe and the hole in which it is located.
anorexia	chronic or constant lack of appetite for food.
aquifer	an underground layer of porous rock, sand, etc, containing water, into which wells can be sunk for water supply purposes.
benthic organisms	all the plants and animals living on or closely associated with the bottom of a body of water.
blind ram	an integral part of the blowout preventer, serving as the closing element. Its rams do not fit around the drill pipe but seal against each other.
block hook	a travelling assembly of one or more pulleys which can be hoisted or lowered in the derrick. The hook is an integral part of the block to which the elevators can be attached. The drill pipe can, in turn, be latched into the elevators and thus raised or lowered in the derrick by the travelling block.
blowout	an uncontrolled flow of gas, oil, or other well fluids into the atmosphere.
blowout preventer (BOP)	the valve-like equipment attached to the casing at a drilling rig used to prevent a blowout.
bottom-hole mud column pressure	the hydrostatic pressure exerted by a static column of drilling fluid (mud) at the bottom of a drilled hole. It is equal to the true vertical depth of the hole multiplied by the specific weight of the drilling fluid.
bottoms-up time	the time required to circulate drilling fluid from the bottom of the hole up the wellbore to the top of the hole.
BOP stack	the combination of valve-like devices, piping, and other fittings attached to the casing at a drilling rig, and designed to prevent a blowout.
carbonate bank	in petroleum geology, a sedimentary structure composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite), sometimes making up a petroleum reservoir.
casing (surface, production)	the steel pipe placed in a well to prevent the collapse of the hole and provide a conduit for fluids during the drilling and producing phases.

APPENDIX 1 (continued)

casing pressure	– the pressure in the casing drill-pipe annulus.
casing shoe	– the bottom end of the casing.
central nervous system	– that part of the nervous system consisting of the brain and spinal cord.
choke	– a valve designed to control flow rates.
choke manifold	– the arrangement of piping and chokes through which drilling mud is circulated to control pressures encountered during a kick.
chronic bronchitis	– the persistant inflammation of the mucous lining of the bronchial tubes.
circulating	– the pumping of drilling fluids down the drill pipe, out through the drilling bit, up the annulus, and back to the mud tanks.
condensate	– that part of natural gas that is liquid at normal atmospheric conditions.
coring	– a drilling operation which uses a special bit to produce a cylindrical sample or core of the rock penetrated.
critical sour well	– a critical sour well has been defined by the ERCB in its Draft Interim Directive issued in April 1984. See Appendix 5 of Appendix 5.
critical zone	– in drilling operations, the critical zone is a zone containing sour gas, generally the target formation.
cytochrome c-oxidase	– cytochrome – any of several iron-containing enzymes found in almost all animal and plant cells, and which are very important in cell respiration.
	– oxidase – any of a group of enzymes which catalyze oxidations.
degasser (mud-gas separator)	– a device which removes formation gas and air from drilling mud.
doghouse	– a small enclosure near the rig floor for protection from the weather for the drilling crew and drilling documents and small tools.
drainage sump	– an earthen pit dug on the lease site for the purpose of collecting potentially contaminated drainage water from the lease.
drill pipe	– the heavy seamless pipe used to rotate the drilling bit and circulate the drilling fluid.
drill string	– the column or string of drill pipe, not including the drill collars or kelly. Often, however, the term is loosely applied to include both the drill pipe and drill collars.
drilling	– the rotating of the drill pipe and bit and the circulating of drilling mud to cause penetration of formations.
drilling program	– a document prepared by the licensee of the well which contains instructions, diagrams, and other pertinent information and is the approved procedure for drilling the well.
drilling spool	– a spacer between components of the BOP stack, containing valved outlets.
emphysema	– a lung condition marked by loss of elasticity of the air sacs (alveoli), causing difficulty in breathing.
enzyme	– a protein able to initiate or accelerate specific chemical reactions in the metabolism of plants and animals; an organic catalyst.

APPENDIX 1 (continued)

epidemiological studies	– the study of the causes and control of widespread and simultaneously occuring health afflictions or epidemics.
excess fluid head	– the pressure exerted by a column of fluid at rest in excess of that which is desired or permissible.
fishing	– an operation to recover equipment such as broken drill pipe that has been lost in the wellbore.
flare line	– a metal pipe running from the choke manifold or from the degasser, terminating at an earthen pit in which gas encountered while drilling may be burned.
flow nipple	– used on the top BOP as a guide for the bit and to direct the mud flow from the well to the mud tanks. Also referred to as a drilling nipple.
formation	– a subsurface layer or deposit that is composed throughout of substantially the same kind of rock.
formation pressure	– the pressure exerted by fluids in a formation. It is also called reservoir pressure or shut-in bottom-hole pressure.
fracture planes	– cracks in a formation that usually occur primarily in one direction or plane (eg, horizontal).
gastrointestinal	– having to do with the stomach and the intestines.
geolograph charts	– the paper recordings made by the Geolograph, a patented device that automatically records the rate of penetration and depth during drilling.
goose neck	– the curved connection between the kelly hose and the swivel.
gradient	– the rate of change, eg, pressure with depth.
gravel berm	– a narrow ledge, shelf, or shoulder composed of gravel.
hold-down equipment	– a mechanical arrangement that prevents the upward movement of equipment installed in a well.
hydraulic	– an action similar to buoyancy, caused by the movement and pressure of a liquid. In blowout situations, the upward force on drill pipe in the hole due to the movement and pressure of the drilling fluid.
hydrogen embrittlement	– the loss of a material's ductility, or ability to deform without fracturing. This is thought to be due to the absorption of hydrogen atoms into the material usually in the presence of water and/or hydrogen sulphide.
hydrogen ion attack	– see hydrogen embrittlement.
hydrogen sulphide (H_2S)	– a naturally occurring poisonous gas.
H_2S scavenger	– a material that deactivates any H_2S entering the wellbore.
hydrostatic pressure	– the pressure exerted by a column of fluid such as the drilling mud in the wellbore.
inside BOPs	– equipment designed to prevent blowout fluids from escaping up the inside of the drill pipe.
interim directive	– announces and prescribes new ERCB policy and requirements. The new policy is normally incorporated into the appropriate regulations at a later date.
intermediate casing	– the string of casing set in a well after the surface casing to keep the hole from caving.

ion	–	an electrically charged atom or group of atoms, the electrical charge of which results when a neutral atom or group of atoms loses or gains one or more electrons during chemical reactions by the action of certain forms of radiant energy, etc. The loss of electrons results in positively charged ion (cation), the gain of electrons in a negatively charged ion (anion).
ionization	–	to change or be changed into ions, eg, as a salt dissolved in water.
iron oxide (Fe_3O_4)	–	a chemical compound which is used as a hydrogen sulphide scavenger.
isopleth	–	an imaginary line surrounding a point of potential contaminant release, formed by joining points of equal potential contaminant concentration (similar to a contour line).
kelly	–	the heavy steel member, four- or six-sided, suspended from the swivel through the rotary table and connected to the top-most joint of drill pipe. It is used to turn the drill stem as the rotary table turns. It has a bored passageway that permits fluid to be circulated into the drill stem and up the annulus, or vice versa.
kelly bale	–	a cylindrical steel bar (similar to the handle or bale of a bucket, only much larger) that supports the swivel and connects it to the hook.
kelly hose	–	the hose on a rotary drilling rig that conducts the drilling fluid from the mud pump and standpipe to the swivel and kelly; also called the mud hose or the rotary hose.
kick	–	the flow of gas, oil, water, or other formation fluids into the wellbore.
kill (top kill)	–	the pumping of high density mud down a wellbore without drill pipe in the hole to overbalance formation pressure.
kill spool	–	a device that connects two BOPs and provides a method of attaching the kill and bleed-off lines to the wellbore. Also known as a drilling spool.
kill stack	–	an assembly of BOPs and related equipment attached to the top of the casing. Generally, the annular preventer is located above two, three or even four ram-type preventers.
lost circulation	–	the loss of drilling fluid from the wellbore into a permeable formation.
master control panel	–	a set of controls that operate the BOPs directly. In contrast, auxiliary or secondary controls operate the BOPs by activating the master control.
monkey board	–	the derrickman's platform that raises him to the proper height to handle the top of the drill pipe as it is run into or out of the hole.
mud (drilling)	–	the liquid circulated down the drill pipe and up the annulus during drilling.
ocular	–	having to do with the eyes or eyesight.
olfactory	–	having to do with the organ of smell (nose) or pertaining to the sense of smell.
one-window concept	–	a concept whereby all communication is relayed through a single person or office in order to make the communication process more efficient.
permeability	–	a measure of the ability of fluids to flow through rock.
pH	–	the acidity or alkalinity of a fluid; a measure of hydrogen ion activity.
piezometer	–	an instrument or drilled hole used to measure pressure or direction of flow.

APPENDIX 1 (continued)

pinnacle reef formation – a geological term referring to a spire-like formation usually composed of limestone, in which hydrocarbons may be trapped.

pipe ram – a sealing component for a blowout preventer that closes the annular space between the pipe and the blowout preventer or wellhead.

pipe stripper – a device which removes mud from the drill pipe exterior, through the use of rubber wipers, as the pipe is being withdrawn from the hole.

porosity – the open or void space within a rock.

porous formation – a bed or deposit composed throughout of substantially the same kind of rocks and containing openings or small spaces within the rock that are usually filled with some fluid, such as oil, water, or gas.

positive pressure air supply – a system used in breathing apparatus whereby the face mask is provided with an air supply of greater pressure than atmospheric pressure, to prevent infiltration into the mask of potentially harmful gases.

prehydrated bentonite – bentonite is a type of clay which is used to increase the viscosity of fresh water, and aid in suspending drilled cuttings. Prehydrated bentonite is mixed and stored in a tank to reduce the time required to mix dry bentonite in an emergency situation.

pup joint – a length of drill pipe, tubing, or casing shorter than the usual 30 feet.

relief well – a well drilled near and deflected into a well that is out of control, making it possible to bring the wild well under control.

respiratory tract – the system of organs involved in the exchange of carbon dioxide and oxygen between an organism and its environment.

riser – a pipe through which liquid travels upwards; a riser pipe.

seepage losses – the escape of the liquid part of a drilling mud into permeable formations; also known as filtration loss.

shear rams – a component of the BOP stack that can cut or shear through the drill pipe and form a seal against well pressure.

sloughing shales – the collapse of the walls of the wellbore due to the swelling and crumbling of shale when exposed to water.

sour gas – natural gas containing H_2S in measurable concentration.

soil microbiology – the branch of biology that deals with the microscopic or ultramicroscopic animal or vegetable organisms found in the soil.

spill-control boom – a series of linked, floating barriers intended to contain and limit the spread of a pollutant spill on water.

spud in – to start drilling the wellbore.

sulphur dioxide (SO_2) – a poisonous gas formed by burning hydrogen sulphide.

surface casing bowl – a heavy metal fitting which is usually welded to the top of the surface casing and which provides a means by which the blowout preventers and the wellhead may be attached.

surge pressure – a pressure wave caused by the rapid lowering of the drill pipe in the confined space of the wellbore.

APPENDIX 1 (continued)

swabbing	– to cause a sucking action within the wellbore by pulling the drill pipe up the wellbore too quickly and accelerating or inducing the invasion of formation fluids.
sweet oil	– oil containing little or no sulphur and hydrogen sulphide.
systemic toxicological effects	– the effects of poisons upon an entire organism or bodily system.
testing	– a procedure to test the type and quantity of fluids contained in a formation.
tracheobronchial tree	– relating to the trachea and bronchi.
travelling block hook latch	– a fastening device on the travelling block hook used to secure the bale of the swivel and prevent it from coming out of the hook.
trip air	– air that enters the drilling mud system during tripping.
tripping (in/out)	– the process of pulling all the drill pipe out of the hole to change a drill bit or other bottom-hole equipment, and then lowering the drill pipe back into the hole.
ungulate	– animals having hoofs, such as deer and moose.
wash to bottom and clear trip air	– circulation of drilling fluid while lowering drill pipe back into the hole. This cleans the hole of drill cuttings and other debris and also flushes air from the joints of drill string as they are added and lowered into the hole.
well effluent	– the substances which flow from a well.
wellhead	– the equipment used to maintain surface control of a well.

APPENDIX 2 LODGEPOLE BLOWOUT INQUIRY — TERMS OF REFERENCE

1. To inquire into, report upon, and make such recommendations as are necessary or advisable in relation to the events and circumstances leading up to and the cause of a sour gas well blowout which occurred on or about the 17th day of October, 1982, near the Hamlet of Lodgepole, in the Province of Alberta, the events following the blowout, and, without restricting the generality of the foregoing, to inquire into, report upon, and make recommendations in respect of the following matters:

   (a) the suitability of the equipment used to drill the well, and the suitability and adequacy of blowout prevention devices installed thereon,

   (b) the regulations regarding licensing the well, rig inspection, and operation of the well site, the adequacy of such regulations and the enforcement of same,

   (c) the measures used to minimize human error as a causative factor in the blowout, including the training of the drilling crew.

   (d) the actions taken by Amoco Canada Petroleum Company Ltd., and others, to prevent and control the blowout, and the adequacy of such actions, including all aspects of occupational health and safety but excluding the two fatalities that resulted from efforts to control the blowout and which fall within an inquiry under the Fatality Inquiries Act.

   (e) the responses following the blowout, by Amoco Canada Petroleum Company Ltd., the Energy Resources Conservation Board staff, government departments, municipalities and others regarding the protection of human health and welfare, the adequacy of such responses, and how such responses were co-ordinated between various agencies, both governmental and private,

   (f) the impact on and hazard to human health and well-being which may have been created by the emissions from the blowout, and

   (g) the environmental effects of the blowout including the effects on

      (i) air,

      (ii) surface and groundwater systems,

      (iii) soils and vegetation,

      (iv) fish, wildlife, and livestock, and

      (v) equipment, buildings, and other types of personal property, and

   the procedures used to control and minimize such effects, the adequacy of such procedures, and how such procedures were co-ordinated between various agencies, both governmental and private.

2. Further to inquire into, report upon, and make such recommendations as are necessary or advisable in relation to the causative factors of sour gas blowouts in Alberta and actions that can be reasonably taken to minimize the possibility of future occurrences.

3. To inquire into and report upon any matters incidental or relating to any of the matters referred to in paragraphs 1 and 2.

ISSUED BY THE LODGEPOLE INQUIRY PANEL

DATED at Calgary, Alberta on 5 May, 1983.

APPENDIX 3 THOSE WHO APPEARED AT PHASE 1 OF THE INQUIRY

Participants and Representatives (Abbreviations Used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) A. L. McLarty S. E. Lipton R. A. Neufeld	
Panel 1	N. J. Rubash, President
Panel 2	J. S. Moore, P.Eng. J. Christian C. O. Grasdal, P.Eng. L. J. Field, P.Eng. P. G. McKenna, P.Eng.
Panel 3	J. S. Moore, P.Eng. G. E. Bullock J. Christian L. J. Field, P.Eng. P. G. McKenna, P.Eng. T. W. Phillips A. J. Thomas
Panel 4	J. S. Moore, P.Eng. J. Christian L. J. Field, P.Eng. D. Heenan, P.Eng. A. J. Thomas
Panel 5	J. S. Moore, P.Eng. R. L. Findlay W. A. Murray, Ph.D., of Promet Environmental Group Limited K. L. Fisher and J. H. Westlake of Monitrex Engineering Ltd.
Panel 6	J. S. Moore, P.Eng. R. L. Findlay D. F. Penner of McCourt Management Ltd. B. Bietz, Ph.D. and R. A. Crowther, Ph.D. of Stanley Associates Engineering Ltd. – IEC Beak Consultant Ltd.
Panel 7	J. S. Moore, P.Eng. R. L. Findlay K. Campbell of Campbell Geoscience Ltd. J. M. Crepin, P.Ag., of Norwest Soil Research Ltd.

APPENDIX 3 (continued)

Panel 7 (cont'd)	P. Eligh of Woodland Resource Services Ltd. D. R. Jaques of Ecosat Geobotanical Surveys Incorporated A. H. Legge, Ph.D. of Kananaskis Centre for Environmental Research and University of Calgary B. Valleau of Western Reclamation Services Ltd.
Panel 8	J. S. Moore, P.Eng. R. Eshpeter W. A. Heth, P.Eng. D. Smith
Panel 9	M. R. Young, M.D., Ph.D. T. H. Milby, M.D., M.S.H. R. P. Smith, M.S., Ph.D.
Panel 10	N. J. Rubash, President
Nabors Drilling Limited (Nabors) D. G. Hart, Q.C.	T. L. Doyle, P.Eng. E. Berg B. Brown W. Randall G. Rode
Energy Resources Conservation Board staff (ERCB) M. J. Bruni D. A. Holgate	L. A. Bellows, P.Eng. E. R. Brushett, P.Eng. R. L. Paulson, C.E.T. J. E. Reid, C.E.T. W. W. Wylie
Alberta Government Departments (Government departments) J. W. Beames, Q.C. A. R. Watson	Alberta Agriculture (AA) R. G. Christian, Ph.D. B. E. Beck, Ph.D. G. G. Klavano, D.V.M. L. E. Lillie, D.V.M., Ph.D. D. Walkey
	Alberta Forest Service Division (AFS) of Energy and Natural Resources (E&NR) J. E. Benson E. G. Jaap A. B. McFadyen
	Fish and Wildlife Division (AFW) of Energy and Natural Resources G. Thompson C. A. Hunt K. Smith D. Wig

APPENDIX 3 (continued)

Alberta Government (cont'd)	Occupational Health and Safety Division of Workers' Health, Safety and Compensation (OH&S) B. J. Johnston I. Arnold, M.D., M.S.C. J. MacPherson E. Ung A. Weiss
	Alberta Disaster Services (ADS) I.D.M. Egener E. Tyler B. Bennett S. R. Langman
	Social Services and Community Health (SS&CH) and Provincial Board of Health (PBOH) S. M. Durkin, M.D. Y. Bhambhani, Ph.D. J. M. O'Laney R. R. Orford, M.D. R. E. Rogers, Ph.D. J. R. Waters, M.D. E. J. Love, M.D., Ph.D. M. L. Russell, M.D.
	Alberta Environment (AE) E. E. Kupchanko, P.Eng. R. N. Briggs, P.Eng. J. F. Kostler, P.Eng. S. Sakiyama A. R. Schulz, P.Eng.
Edmonton Area Respiratory Patients (EARP) W. W. Smart	C. May G. McPherson M. Semaka A. S. Clanachan, Ph.D.
N. E. Brown, M.D.	N. E. Brown, M.D.
C. Sams	C. Sams W. Campbell
Town of Drayton Valley	Hon. R. Mayhew, Mayor I. Dykes
Royal Canadian Mounted Police Drayton Valley Detachment (RCMP) P. Kirwin	Staff Sergeant, L. Bannerman
County of Parkland No. 31	Staff Sergeant, R. Steele

APPENDIX 3 (continued)

Canadian Institute of Public Health Inspectors – Alberta Branch (CIPHI) T. Hodge M. D. MacKenzie	R. Greenwood, Ph.D. T. Hodge
Alberta West Central Health Unit (Health Unit) H. B. Madill	N. J. Bayliss, M.B., B.S., M.P.H., F.R.S.H.
Public Advisory Committee to the Environment Council of Alberta (PAC)	M. S. Kostuch, D.V.M. S. W. Behie, P.Eng., Ph.D., P. R. Guy, B.Sc., M.Sc., and R. L. Johnson, B.Sc., M.Sc. of Monenco Consultants Limited
Health Unit Association of Alberta N. J. Bayliss, M.B., B.S., M.P.H., F.R.S.H.	
Shell Canada Resources Ltd. J. D. Courtwright	
Canterra Energy Ltd., Canadian Petroleum Association, Independent Petroleum Association of Canada, and Canadian Association of Oilwell Drilling Contractors C. P. MacDonald	
Environmental Law Centre L. F. Duncan T. Foley	
City of Edmonton and Edmonton Board of Health M. A. McAvoy	
Pembina Area Sour Gas Exposures Committee (PASGEC) J. C. Prowse, Q.C. D. P. Mallon	Steering Committee R. Macintosh D. Baker O. Baker M. Grinde C. Strach C. Whitelock W. Elton, M.B.A., of WIN Consulting Corporation Ltd. Lodgepole Area Panel D. Baker O. Baker D. Belair L. Nail T. Wentland

APPENDIX 3 (continued)

PASGEC (cont'd)

Violet Grove Area Panel
C. Andersen
C. Andersen
J. Bolianatz
D. McGhee
C. Whitelock

Buck Creek Area Panel
C. Rosell
W. D. Rosell
R. Sackela
A. Wasser

Cynthia Area Panel
R. Beck
M. Grinde
D. Nichols
J. Penner
C. Strach

Easyford Area Panel
D. Huska
J. Huska
B. Kynoch
L. Macintosh
R. Macintosh
D. Vowk

Drayton Valley Panel
J. Benger
E. Gottschalk
O. Guze
J. Rowles
J. Stewart

Health Panel
L. Horstman, B.Sc., M.Sc.
K. E. Josephson, D.V.M., of
Rocky Rapids Veterinary Service
R. Macintosh

R. Cowdery

E. Struzik of
The Edmonton Journal

Informal Session – Drayton Valley, 23 November 1983
Members of the Public

H. Luethi
Mrs. Henkle
S. McConnell
C. Rosell
L. Beckett
D. Gramlich
W. Rosell
L. Smeland
C. Cavanagh
O. Guze
W. Shirvell

APPENDIX 3 (continued)

Informal Session – Edmonton, 8 December 1983

Members of the Public		
	Mr. Welsh	A. Bosman
	Mr. Barnett	E. Hall
	L. Mallett	C. Sams

Inquiry Staff

R. D. Schachter
A. R. Currie
D. G. Harrington, P.Ag.
J. K. Moloney
E. J. Morin, P.Eng.
A. S. Murray, P.Eng.
R. W. Reid, Ph.D.

APPENDIX 4 POSITIONS OF THE PARTICIPANTS

Introduction

The following is a summary of the views of each of the participants in Phase 1 of the inquiry. Most of the participants presented evidence and oral argument in support of their positions and responded to questions from the Panel, its counsel, and others. That evidence and the transcripts are part of the public record and have not been reproduced in this report. Rather, the Panel has attempted to synthesize the evidence and arguments into brief summary statements reflecting the positions of each of the participants.

1 Amoco Canada Petroleum Company Ltd. (Amoco)

Amoco's position with respect to the various matters considered at Phase 1 of the inquiry can be summarized as follows:

1.1 The geological knowledge of the area prior to the drilling of the 13-12 well was such that a sweet oil well was anticipated by Amoco as the likely result. Drilling would not have proceeded had it been known that sour gas would be encountered but the involved personnel were aware of that possibility. However, there would have been no significant changes in the planning for or equipment and procedures used had the well been drilled with the knowledge that sour gas would result.

1.2 The cause of the blowout can likely be traced to an initial influx of sour gas into the wellbore during coring operations when the drill pipe and coring assembly were pulled up off the bottom of the hole to insert a small joint of pipe. The gas was not fully circulated out of the mud system due to the failure of the degasser, which is intended to separate the gas from the mud. The degasser float valve, which is intended to allow the mud to circulate into the tank while diverting the gas to a flare, became stuck on two occasions, forcing a halt to the circulation of the mud down through the centre of the drill pipe and up around its outside.

These failures were worsened by cold weather and coupled with other equipment problems allowed additional volumes of gas to enter the wellbore. The problems also caused the circulation of mud to be halted several times leaving the sour gas in contact with the drill pipe for longer than normal. The H_2S in the gas caused embrittlement of the pipe and it subsequently parted several hundred metres below the floor of the drilling rig. The pressure in the wellbore then caused the pipe to be forced upward out of the hole. This severed the kelly hose connection to the drill pipe thus allowing the well to blow out through the centre of the pipe.

1.3 The Nabors rig used by Amoco was more than adequate to drill the planned well and it had been inspected and found satisfactory by senior Amoco personnel prior to its service for the company.

1.4 Amoco decided to use Grade G high-carbon steel drill pipe as part of the drill string in order to have pipe with sufficient tensile strength to drill a directional hole to a depth of some 3200 m even though it recognized that the pipe would be more susceptible to H_2S attack. In future similar situations, Amoco said it would use Grade E pipe of greater wall thickness but defended the choice of its drill string as suitable given the existing circumstances and expectations when the 13-12 well had been planned.

1.5 The closed-type degasser, with a float valve on which its functioning is dependent, which was on the Nabors rig, had been used without serious problems on most rigs drilling in very cold climates where the mud tank and equipment were housed. The choice of such equipment was therefore justifiable. On the basis of the problems encountered, Amoco would in future require an open-bottom unrestricted flow-type degasser with a by-pass if repairs became necessary.

1.6 The overall drilling mud program including the volume of ingredients and equipment available to mix the mud, the density, and other properties of the mud in use at the time of the blowout, and the use of iron oxide in the mud as an H_2S scavenger, were all in accordance with sound practices and were not the direct cause of the blowout.

1.7 The blowout prevention equipment, the manner in which it was installed, and the testing of it as required by Amoco more than exceeded the requirements of the ERCB and acceptable industry standards.

1.8 Amoco personnel and the Nabors drilling crew were all well-trained individuals with more than sufficient experience to drill the subject well located in a sour gas prone area. Also, adequate planning meetings to review blowout prevention and sour gas kick-control procedures took place to ensure that the personnel were adequately familiar with the planned drilling program. Additionally, even though the senior supervisory personnel were forced by problems to work very long hours during the night and morning of 16 and 17 October, they were completely capable of properly discharging their responsibilities and their long periods on duty did not contribute to the cause of the blowout.

1.9 The well site was selected and prepared for drilling in a manner completely consistent with the terrain and so as to reduce potential environmental impacts.

1.10 The drilling of the well, including the setting of surface and intermediate casing and the use of directional drilling equipment, to the top of the Nisku zone was relatively routine and that part of the operation played no part in the cause of the blowout.

1.11 The planning with respect to safety, including procedures if H_2S gas was encountered, was properly done and complied with regulatory requirements and industry standards.

1.12 The actions taken during the night and morning of 16 and 17 October while problems were being encountered were consistent with kick-control and other industry accepted procedures. These included activities at the time gas was noted bubbling out of the casing, when the degasser failed on two occasions, and when the drill pipe parted. Amoco acknowledged that alternative actions could have been followed by those responsible, possibly with greater success, however, the decisions taken were all logical and sound given the circumstances that existed at the time.

1.13 The Amoco emergency response plan, although general in nature, was appropriate for dealing with the blowout. Under terms of the plan, the blowout was a Condition IV, the most extreme designation recognized.

In terms of the on-site situation, adherence to the plan resulted in the immediate notification of senior company personnel, engagement of well- control specialists, notification of the ERCB, and plans for control procedures. It also included general plans for on-site safety and for securing the site from the public.

With respect to the off-site situation, the Amoco emergency response plan was adequate to ensure that immediate steps were taken to protect the public during the period when Amoco and involved government representatives were developing more specific plans to deal with off-site problems.

1.14 The personnel used to bring the well under control, both from within the Amoco organization and from outside specialist companies, were well trained and had the proper experience to deal with the blowout. Amoco emphasized that the change in well-control specialists that took place during the latter stages of the blowout period was made because the strategy changed to one of capping the well while on fire. This necessitated the change since the first specialist company was not prepared to undertake the operation while the well was burning.

1.15 The equipment necessary to control the well was available as needed and did not significantly delay well-control operations, in part, because Amoco was able to marshal considerable resources to bring it in from remote locations or fabricate it as appropriate.

1.16 The weather conditions during capping operations, and particularly atmospheric conditions that caused H_2S gas to build up around the well site, significantly impacted on control operations and lengthened the period over which the well blew wild.

1.17 The plans to cap the well, and particularly the sequence of the various methods attempted, were well thought out and technically sound.

The first plan was to lower a new blowout preventer over the drill pipe stub and bolt it to the preventer in place. Amoco acknowledged that the failure of its own personnel and those of Nabors to recall that an automatic pipe cleaner was installed as part of the rig facility meant that several days were spent in preparing for this particular procedure which, in the final analysis, could not be attempted. It stressed that much of the work during that period would, however, have been needed in any case.

The second plan was to open the pipe blowout preventers, drop the drill pipe into the hole, and then close the other preventers (blind rams which closed against each other). Amoco said it recognized the pipe might blow out of the hole rather than drop (as it did, causing the first fire), but that this plan was still the best available and had to be tried.

The third plan was to extinguish the flame with explosives and lower a new control assembly over the casing stub. This plan was aborted by an accident which occurred a few minutes before it should have succeeded.

The well subsequently caught fire and was capped while on fire by installing a new control assembly.

1.18 The decision in the early stages to cap the well when it was not on fire, and thus was emitting H_2S, was taken because of added difficulties in capping a burning well. Such a procedure had been accomplished on only six previous occasions. The later decision to attempt to control it while it was on fire was taken because of the widespread nuisance effects that were occurring and because of public concerns.

1.19 The on-site safety procedures during the blowout were in accordance with accepted procedures and all regulatory requirements. Experienced safety personnel were engaged and were given proper authority, and equipment consistent with the existing safety hazard was available at all times. Problems which did occur were the result of unexplained and unique circumstances and could not reasonably have been avoided.

1.20 Amoco personnel on site at the time of the blowout had authority to ignite the well, thus converting the H_2S to SO_2, if the H_2S represented an immediate serious threat to the safety of the public. Immediate ignition was not necessary, but Amoco remained prepared throughout the blowout to ignite the well at any time the public was threatened.

1.21 Plans were put in place, including site preparation and allocation of a rig to drill a relief hole, if surface attempts to kill the well were unsuccessful. This approach was not used, however, because it would require some 65 to 80 days to drill a relief hole and then the procedure might not be successful.

1.22 Amoco agreed with the one-window concept in terms of contacts with Government departments and agencies and dealt primarily with the staff of the ERCB.

1.23 The site was properly secured from the public and access was accorded only to those parties involved in well-control operations and only with adequate safety equipment.

1.24 Off-site monitoring for H_2S was taking place within hours of the beginning of the blowout and continued whenever H_2S was being emitted. The amount of monitoring was more extensive than had occurred in a single area on previous occasions in that nine monitors, five mobile and four stationary, were used.

The number of monitors, the region being monitored, and the concept of portable monitors following and attempting to establish areas of peak concentration were adequate to ensure the safety of the public.

1.25 Residents in the immediate area of the 13-12 well and of the community of Lodgepole were informed of the blowout and the possible need for evacuation. The members of the public not contacted were generally farther from the well site and were not in substantial danger.

1.26 Upon request, residents of the immediate area that believed they were experiencing health impacts were moved at Amoco's expense. Some 28 persons were moved to locations ranging from Drayton Valley to Edmonton for periods of up to a week or more but generally in the order of one day.

1.27 Amoco, on the basis of its involvment with government representatives, understood that the following guidelines for notification and evacuation of the public were adopted:

(a) For H_2S at 5 ppm for 6 hours or 10 ppm for 1 hour, residents would be notified of the levels and evacuation would be recommended.

(b) For H_2S at 15 ppm with an upward trend or any reading of 20 ppm would bring about a mandatory evacuation.

(c) For SO_2, 0.3 ppm for 24 hours would result in notification and recommended evacuation of residents.

Amoco undertook to be responsible for the notification process and, at that time, indicated it would assist if residents took the advice and voluntarily evacuated. Amoco had no responsibility with respect to mandatory evacuation.

1.28 Amoco's phone number was readily available to the public and complaints were recorded and investigated when made. Additionally, many Amoco employees reside, and are well known, in the area and were available to receive complaints and pass them on to the company.

1.29 During the early stages of the blowout, media briefings were not considered necessary. However, contacts by the media were responded to as soon as possible or as new information was available. During later stages, media briefings were held more frequently as a result of what Amoco perceived to be increasing concerns regarding health impacts and a tendency on the part of the media to sensationalize the event and mislead the public.

1.30 Amoco followed procedures throughout the blowout, such as diking drainage channels, to minimize the likelihood of condensate from the well getting into the Pembina River and other surface or groundwater systems.

1.31 Actions were implemented during the blowout phase to ensure the collection of sufficient information to measure impacts on the environment, including wildlife, and to support reclamation of the area.

1.32 The impact of H_2S on humans may be immediate death if levels reach as high as 1000 or 1500 ppm. Provincial air quality standards are set on the basis of avoiding nuisance impacts and are 0.01 ppm for a 1-hour period. Particularly sensitive persons may detect an odour at that level. The occupational health standard allows workers without breathing equipment to remain at work in concentrations of 10 ppm for 8 hours a day.

1.33 The monitoring for H_2S indicated peak readings for very short time periods of some 15 ppm in the general region of the well site that might be populated by the public (within 20 km). Beyond that, H_2S readings were very low, although the 0.01 ppm nuisance standard was probably exceeded about 3 per cent of the time for significant parts of the province.

1.34 The overall health of the public was not affected by emissions from the blowout. The extreme pungent odour of H_2S was a nuisance, causing discomfort and perhaps even vomiting in instances, but there were no long-term impacts of H_2S at the low levels experienced by the public.

1.35 Forest cover was destroyed and cleared in the 290 ha immediately adjacent to the 13-12 well. It was modestly affected by condensate to varying degrees over an additional 600 ha. The cleared area can be successfully reforested and the impacted areas beyond that will fully recover from the effects of the blowout.

The impact of H_2S and SO_2 on the forest cover was not great and much of it will be eliminated with time.

1.36 The substantial negative impact on soil was limited to some 40 ha with the most serious impact occurring only over about 16 ha. The productivity of most of these soils can be fully restored.

1.37 The effects of well effluents on surface waters was largely confined to the Pembina River and Zeta Creek and was limited in nature, although some slight seepage continues. The snow and some ice which was saturated with condensate was removed as soon as was practical. No lasting impacts on surface waters or on aquatic life are expected.

1.38 Impacts on wildlife were negligible. An evacuation and avoidance of the area occurred during the blowout and the period immediately thereafter. Wildlife can be expected to return to the area and certain species may be attracted to the cleared area during the period of reforestation in numbers greater than normal. Very few, if any, deaths among wildlife can be definitely attributed to the blowout and there is no evidence to suggest mutations have occurred.

1.39 Amoco was in the process of dealing with claims respecting alleged impacts on livestock, buildings, and equipment during the period of the inquiry, and thus it offered no views on these matters.

1.40 On the basis of information available up to the time of the inquiry, the well was likely blowing at a rate of some 1.4×10^6 m^3 per day and the gas probably contained 23 to 25 per cent H_2S and 750 m^3 of condensate per million cubic metres of gas.

2 Nabors Drilling Ltd. (Nabors)

The overall position of Nabors with respect to the blowout can be summarized as follows:

2.1 Nabors specializes in deep-hole drilling and its record in terms of safety and prevention of blowouts is excellent.

2.2 The rig met all 35 requirements of ERCB regulations and the rig workers exceeded normal training requirements.

2.3 Specific responsibility for types of equipment used and actions taken during periods when problems were occurring rested with Amoco, but Nabors had competent, experienced staff on site that consulted with Amoco on a continuous basis.

2.4 The blowout occurred as a result of a series of equipment failures described in detail by Amoco with the principal cause being the failure of the drill pipe.

2.5 The drilling crews were generally aware of the potential for H_2S gas in the area and were properly trained to deal with it.

2.6 The suitability of the drill pipe for sour gas service was not specifically considered by Nabors since it was the responsibility of Amoco.

2.7 BOP tests were conducted as required by the regulations, even though they were not all recorded in the daily drilling reports.

2.8 There were times during the night and morning of 16 and 17 October when operations were delayed due to lack of men. Even though there was the normal full complement of workers available, additional workers could have been used.

2.9 Procedures consistent with industry practice were used when dealing with the gas influx problems. Similar procedures and equipment, including details such as the iron oxide scavenger and the type of drill pipe, had been successfully employed during a sour gas kick on another well.

3 Staff of the Energy Resources Conservation Board (ERCB)

The position of the ERCB staff with respect to the blowout and subsequent events can be generally summarized as follows:

3.1 The licensee of a well which blows wild is normally allowed to retain responsibility for control of the well because of its familiarity with the area, and because the licensee usually has personnel and equipment readily available.

3.2 The drilling contractor's role in a major blowout is limited to assisting the well-control specialist where appropriate.

3.3 The ERCB may take control of the capping operations at a blowout, but this is not the normal practice. Where actual control is not taken, the ERCB staff role is to review and approve the control program, satisfy itself with respect to action taken to protect the public and the environment, properly secure the site, and liaise with other Government departments, the public, and media representatives.

3.4 The 13-12 well was properly licensed in accordance with existing legislation and practices. The rig was inspected and found to be satisfactory.

3.5 Amoco co-operated fully with the staff respecting control operations and its control plans were generally acceptable to the staff. The question of flaring the well to convert the H_2S to SO_2 was discussed with Amoco on several occasions, as was the possible drilling of a relief well. These matters were adequately considered by Amoco.

3.6 The monitoring program was the responsibility of Alberta Environment. The monitoring carried out was extensive and appeared sufficient to safeguard against serious impacts on the public. The staff were involved in establishing evacuation criteria, but the ERCB has no authority to order an evacuation.

3.7 Environmental controls and studies were adequate to minimize the impacts and to allow proper restoration.

3.8 Clean-up operations were properly carried out, but on-going work is required to accomplish complete rehabilitation.

3.9 There was not a detailed emergency plan requested for the 13-12 well because of its general remoteness from populated areas.

3.10 The one-window concept for contact between Amoco and Government departments appeared to work reasonably well. However, there were problems in co-ordinating efforts related to the media and in dealing with complaints and questions from the public. Additionally, clarification as to certain responsibilities, for example mandatory evacuation and contact with the media, is needed.

4 Government Departments

Six Government departments participated in the inquiry. They each presented witnesses and written evidence setting out their involvement in and views respecting the blowout. The overall position of each of the departments is summarized in the following:

4.1 Alberta Agriculture (AA)

The views of AA were based on visits to several farms in the area during the blowout, submissions to the provincial laboratory from the blowout area both during and following the incident, discussions at a series of public meetings, and visits with district agriculturists and veterinary practitioners in the area.

4.1.1 Damage to agricultural plants did not occur because they were not growing at the time of the blowout.

4.1.2 Disease conditions found in submissions to the laboratory could not be shown to be related to H_2S.

4.1.3 The pattern of diseases diagnosed by the laboratory from the area near the blowout was one that would normally be expected if the blowout had not occurred.

4.1.4 The number of aborted fetuses available for examination was insufficient for statistical evaluation, but no pattern that could be related to H_2S was detected.

4.1.5 Review of literature and air monitoring data indicates that the levels and duration of exposure of livestock to H_2S or SO_2 during the blowout would not have been expected to cause changes other than transient irritation to eyes and the respiratory system.

4.1.6 A study under way at the Vegreville laboratory indicates that there may have been transient but measurable effects from the emissions on enzymes in livestock. There is no conclusive evidence of irreversible changes and harmful effects are neither confirmed nor denied. Further work is needed.

4.1.7 Amoco is to file a more detailed livestock impact report with the department following the settling of claims.

4.1.8 Co-ordination of government and Amoco contacts by the ERCB was reasonable. A central contact group is a good idea, but technical questions should be referred to others for response.

4.2 Energy and Natural Resources (E&NR)

This department called witnesses from Alberta Forest Service (AFS) and Alberta Fish and Wildlife (AFW). Their positions respecting the blowout can be summarized as follows:

4.2.1 The operating company is responsible for containment, clean-up, and restoration of disturbed public forest land. During an emergency, the ERCB plays a co-ordinating role, but ensuring satisfactory clean-up and restoration is the responsibility of AFS.

4.2.2 An amended surface lease was granted to Amoco in February 1982. The approved surface location had been moved north of the Pembina River due to environmental concerns about drilling in an oxbow south of the river and because of a critical wildlife area.

4.2.3 The department was informed of the blowout on 17 October and representatives arrived in Drayton Valley on 18 October. A representative was either at Drayton Valley or in daily telephone contact with Drayton Valley thoughout the blowout.

4.2.4 Approval of activities to facilitate control of the well were given in a prompt and responsible manner. Examples of activities include clearing and construction of access roads, river and creek crossings, and drainage sumps, and removal and salvage of timber from the site.

4.2.5 If such a blowout was to occur in hot summer weather, it might have to be ignited because the unburned condensate collecting on trees would represent a fire hazard.

4.2.6 Short-term rehabilitation was commenced by Amoco under direction from AFS immediately following the blowout. All trees more than 50 per cent covered with condensate were cleared (some 290 ha). Levelling and seeding to grass was done and seedlings were obtained for reforestation to begin in 1984.

4.2.7 Planning for long-term rehabilitation is under way and successful reclamation can be expected.

4.2.8 There is no evidence of significant impact on fish or wildlife from the blowout.

4.2.9 The one-window approach involving the ERCB as the main Amoco contact functioned well but a central command post was needed to co-ordinate government activities during the emergency and to communicate with the public. The concept of a response team might include public input.

4.3 Workers' Health, Safety and Compensation

The Occupational Health and Safety Division (OH&S) of this department presented evidence regarding its involvement in and views of the blowout. Its position can be summarized as follows:

4.3.1 The relevant responsibility of the division is to attempt to prevent workplace injuries and illnesses through regulation, promotion, inspection, and investigation.

4.3.2 The division learned of the blowout on 18 October and was in telephone contact with Amoco. An inspector was dispatched to the area on 20 October and spent considerable time in the area throughout the period of the blowout.

4.3.3 Representatives of the division attended many safety and planning meetings and inspected safety equipment. The planning procedures and equipment were generally found acceptable and no contraventions of legislation or regulations were detected.

4.3.4 There was discussion on 21 October of igniting the well to provide a safer environment for workers. Nothing further was done because the capping was expected to take only a few days. An assessment is needed of the relative safety risks of capping a well burning as opposed to not burning.

4.3.5 Following an accident on 16 November and subsequent meetings on 17 and 18 November, the division required the use of positive pressure-type breathing apparatuses rather than the demand-type which had been previously used. A mask-up requirement at 20 ppm of H_2S was also imposed to replace an earlier practice of masking up at 50 ppm.

4.3.6 Medical representatives from the division were involved with Amoco in formulating a co-operative follow-up health study of workers involved on the blowout site.

4.3.7 The OH&S standards for H_2S are an average of 10 ppm for 8 hours, 15 ppm for 15 minutes, and a maximum of 20 ppm as the mask-up ceiling. For SO_2, the standard for workers is an average of 2 ppm for 8 hours, 5 ppm for 15 minutes, and a 20-ppm ceiling. For both H_2S and SO_2, the 8-hour standards include the additional proviso that there must be a minimum 60-minute interval between each exposure and no more than four exposures per day.

4.3.8 The ERCB's co-ordination of company and government involvement was acceptable, but a better means of communication with the public is needed.

4.4 Alberta Disaster Services (ADS)

The position taken by ADS respecting the blowout is summarized in the following:

4.4.1 ADS co-ordinates, advises, and trains respecting emergency planning in the province.

4.4.2 ADS learned of the blowout on 17 October, made many visits to the area while it was uncontrolled, and was in general contact with Amoco, other Government departments, involved local authorities, and other agencies for the duration of the incident.

4.4.3 An Order in Council or a declaration by a local authority is required for a "state of emergency" to exist, which in turn allows mandatory evacuation of citizens. A state of emergency was not declared because Amoco, local and other authorities, and involved Government departments or agencies were handling the situation in an acceptable manner. Voluntary evacuation is usually very effective and, to the limited extent needed, was in this case with Amoco playing a lead role.

4.4.4 The one-window concept for government-Amoco contact with the ERCB as a co-ordinator worked reasonably well, but better communications with the public, perhaps including paid announcements, were needed to overcome misinterpretation of the situation. Co-ordination does not mean one group has control over others, but rather that information is exchanged, and this took place.

4.5 Social Services and Community Health (SS&CH) and the Provincial Board of Health (PBOH)

SS&CH has close ties with the PBOH, both in terms of responsibilities and key personnel. The Deputy Minister of SS&CH is, by virtue of the office, the Chairman of the PBOH. The action taken and positions of these organizations with respect to the blowout is summarized in the following:

4.5.1 In the early stages of the blowout, discussions took place to ensure that the necessary actions were being carried out. These included efforts to control the well and appropriate monitoring. As it became clear that the well was not being controlled as quickly as expected, the PBOH began a co-ordination role in terms of possible health impacts.

4.5.2 A 24-hour complaint line was established. Of a total of 1477 complaints, 491 health-related complaints, with 31 different symptoms, were received. The frequency of complaints received was not always consistent with the H_2S levels which were being monitored.

4.5.3 Discussions with other involved parties took place respecting the gathering of relevant data, studies of health effects of H_2S, the holding of seminars on H_2S, the development of evacuation criteria, and public relations aspects of sour gas blowouts.

4.5.4 A committee established a list of health-related questions and recommended the development of a systemized research plan to scientifically address them. The PBOH endorsed that approach, but delayed further action pending the outcome of the subject ERCB inquiry.

4.5.5 A committee prepared an information brochure on H_2S to be made available to the public. Evacuation criteria and advice to the public as to actions that should be taken in the event of exposure to H_2S were included in the brochure.

4.5.6 The design of a study on pregnancies in the Lodgepole area was commissioned. Dr. Love, who carried out the work, concluded that a proper study was not possible because an adequate number of H_2S level readings did not exist, the recorded levels of H_2S were so low that impacts would not be expected, there were only a small number of pregnancies in the area at the time, and a rubella epidemic was having an impact on the spontaneous abortion rate.

4.5.7 No significant health hazard existed for the general public, but it is recognized that there is not sufficient research data available to clearly determine whether health impacts can occur as a result of low-level, long-term exposure to H_2S. Similarly, data does not show that respiratory patients are more susceptible to tissue damage from H_2S, but studies of actual situations suggest that they likely are.

4.5.8 Better effort could and should have been made to see that the proper information respecting the Lodgepole blowout was being provided to the general public.

4.5.9 The PBOH should be involved in the setting of evacuation limits and in decisions respecting the intentional ignition of sour gas blowouts. Special evacuation levels may be required for sensitive individuals.

4.6 Alberta Environment (AE)

The evidence presented to the inquiry by AE is summarized in the following:

4.6.1 The responsibility of AE in the case of a blowout is to protect the environment. The department does not have a direct responsibility in terms of controlling the blowout, but its advice and direction may affect the manner in which the well will ultimately be controlled. In the particular instance of the Lodgepole blowout, AE was involved in discussions on a regular basis with respect to intentionally igniting the well during much of the relevant period of the blowout.

4.6.2 The one-window concept with the ERCB being the main contact with the operator worked effectively in the case of the Lodgepole blowout and should generally be retained. Communications with the public, however, left something to be desired. A follow-up survey by AE respecting the notification of emergency that took place in Cynthia revealed that the process would have been more effective if it was better organized and if the residents contacted had been given better information.

4.6.3 AE conducted a portion of the monitoring which took place and also co-ordinated all of the monitoring, including that carried out by Amoco and the ERCB. AE has a philosophy that the operator should have monitoring responsibilities which includes paying for its own monitoring units. The number of units needed is dependent on each particular situation and, in this case, was sufficient to ensure safety of the public.

4.6.4 The highest recorded levels of H_2S were in the order of 30 ppm away from populated areas. Twenty-three ppm was the highest recorded level at residences and 14.5 ppm was the highest level recorded in communities. The highest SO_2 reading recorded was 0.275 ppm near Edson.

4.6.5 AE had understood throughout the duration of the blowout that if concentrations of H_2S reached 20 ppm at Drayton Valley, the well would be ignited.

4.6.6 The deposition rates for sulphur, as calculated by Monenco Consultants Limited (Monenco) in a submission made on behalf of the Public Advisory Committee of the Environment Council of Alberta, were inaccurate and much too high.

4.6.7 There is no evidence of significant or lasting impact on the environment, other than for the immediately surrounding area of the 13-12 well where condensate saturation took place and the trees were ultimately removed. It is anticipated that reforestation of this area can be successfully accomplished.

4.6.8 An emergency response plan should be in place where sour gas blowouts might occur and it should be the responsibility of the operator preparing the plan to include the name and the location of residents within the area which could be significantly affected by a blowout.

4.6.9 The experience gained during the 13-12 blowout led to the following recommendations:

(a) a system is required which will make available accurate flow information at the outset of a blowout,

(b) a review should be made of the industry's ability to respond quickly to extensive monitoring requirements,

(c) the composition of all possible gaseous emissions from Alberta oil and gas pools should be determined,

(d) AE should be given full control of off-site monitoring during sour gas blowouts,

(e) communications with the public respecting blowouts must be greatly improved, and

(f) criteria for the firing of sour gas wells should be made part of the well licence.

5 The Public Advisory Committee of the Environment Council of Alberta (PAC)

Representatives of Monenco appeared on behalf of PAC and presented the results of an environmental investigation. A representative of PAC also presented certain recommendations that arose as a result of the blowout. The evidence can be summarized as follows:

5.1 Sulphur deposition as a result of the blowout amounted to some 15 to 35 kg/ha over a very large area of some 1400 square kilometres. This gives reason for concern even though it is not known whether negative impacts such as soil acidification resulted from this deposition.

5.2 Some 1950 ha immediately surrounding the wellbore were visibly affected due to deposition of alkaline formation water. Some 270 ha experienced some damage as a result of condensate and some 37 ha were totally saturated with condensate. There is no real evidence available to support the conclusion that complete reforestation will be possible.

5.3 Sufficient concern has arisen as a result of the blowout and the following investigation to raise serious questions as to whether lasting environmental impacts occurred. Should there be similar blowouts in the future, environmental data should be collected from the outset and major environmental impact studies should be initiated as soon as possible.

5.4 There appeared to be confusion throughout the 13-12 blowout as to which Government department or agency had the co-ordinating role with respect to the environment.

5.5 In the case of sour gas blowouts, government officials should take charge of and carry out all of the monitoring to ensure that the data is available to the public and that it has credibility. The operator could be held financially responsible for the monitoring, but should not play a direct role in it.

5.6 A medical protocol should be put in place so that data could be immediately gathered and studies commenced if a future sour gas blowout occurs.

5.7 Government representatives should have the responsiblity of deciding when evacuation is necessary and of directing it, except for the immediate response if an emergency exists within a few hours of a blowout, during which time the operator would be expected to act.

5.8 AE should be responsible for gathering the necessary data and commissioning or carrying out the necessary studies to determine if serious environmental impacts have occurred.

6 Pembina Area Sour Gas Exposures Committee (PASGEC)

PASGEC produced a large number of witnesses, most of whom are residents of the general area. The witnesses described to the panel the situation as they perceived it during the blowout. PASGEC also commissioned a survey which was conducted by WIN Consulting Corporation Ltd. The evidence put forward on behalf of PASGEC is summarized in the following:

6.1 PASGEC is not anti-industry, but merely wished to put its views forward and to receive answers to a number of questions.

6.2 Since the government and Amoco appeared evasive when contacted during the blowout, and since Amoco had experienced a previous blowout in the area, PASGEC reached the general conclusion that the incident could have been avoided.

6.3 Insufficient information was made available to the public, particularly with respect to monitoring results. PASGEC questioned whether an adequate number of monitors were available, whether the instrument ranges were adequate, and whether organization and co-ordination of the monitoring was appropriate.

6.4 Most people in the area were never contacted and, unless they phoned, never heard from Amoco, the ERCB, or Government departments. In some instances, even upon phoning, they received what appeared to be a runaround. Little information was made available regarding the willingness or otherwise of Amoco to evacuate persons from the area.

6.5 Individual monitoring equipment, such as Drager tubes, should have been distributed to the general population in the area. Additionally, a booklet or some other form of information and advice respecting H_2S should have been made available.

6.6 Some three-quarters of the people surveyed believed they experienced symptoms from H_2S and some 60 per cent were of the view that the blowout could have been prevented. Almost all individuals surveyed considered that a poor job had been done by Amoco, the ERCB, and Government departments in providing information to the public.

6.7 Certain individuals who reside in the area and have respiratory problems experienced extreme difficulties during the blowout. These individuals should have been evacuated at the outset of the incident.

6.8 Many individuals experienced one or more symptoms such as burning eyes, headaches, sore throats, chest pains, breathing difficulties, coughs, stomach cramps, gas pains, nausea, listlessness, or insomnia.

6.9 Animals experienced runny eyes, coughing spells, scours, and general weight loss. Calves born in the spring following the blowout were smaller than normal and did not gain weight as would be expected. Spontaneous abortions among livestock appeared to be somewhat higher than normal.

6.10 Birds and small animals seemed to disappear from the area and were slow to return.

6.11 Silverware, jewellry, and other ornaments or china discoloured during the blowout, and houseplants generally died.

6.12 Paint peeled off of many buildings, and machines and fences seemed to rust more rapidly than normal.

6.13 Many individuals found that discomforts occurred even while the well was on fire. Consequently, there was not unanimity that a sour gas well should automatically be fired if it blows out. Most of the participants from the public indicated that the important thing was to prevent blowouts wherever feasible and, where they did occur, to ensure that they were controlled as soon as possible.

7 Canadian Institute of Public Health Inspectors (CIPHI)

CIPHI, through Dr. Greenwood, a consultant, took the following position respecting the blowout:

7.1 Bureaucratic organizations are typically able to handle routine events on the basis of prearranged plans, but are not readily able to handle non-routine events.

7.2 With respect to the 13-12 blowout, there was a lack of clarity in responsibility and co-ordination between various involved parties, particularly Government departments.

7.3 There was insufficient information available as to the residences of persons who might have needed evacuation. This is a deficiency that must be resolved in the event of future similar blowouts.

7.4 A task force, with a clearly designated leader, should be in place to handle future blowouts. The task force should have the authority to prescribe evacuation levels and to take actions such as requiring the immediate firing of the well.

8 Edmonton Area Respiratory Patients (EARP)

This group was formed as a result of the blowout and is made up of individuals in the Edmonton area that suffer from serious respiratory problems. Many of them are fully hospitalized and others are out-patients. The views they expressed at the inquiry may be summarized as follows:

8.1 Some 20.53 per cent of all Canadians have respiratory problems and are thus more susceptible to pollutants. EARP represents a good cross-section in terms of the various respiratory ailments.

8.2 The patients believed they experienced more breathing and similar problems during the blowout than in the same period in other years. This was confirmed by a chart study for 32 in-patients and 28 out-patients which generally indicated greater problems during the blowout than immediately before or after it.

8.3 More scientific research is needed, particularly with respect to long-term exposure to low levels of H_2S, impact of H_2S on sensitive individuals including respiratory patients and young or old, and the interaction of H_2S and other chemicals. Some of this research could be facilitated by concentrating on individuals who work in H_2S environments or live in communities where low-level concentrations frequently occur.

8.4 The World Health Organization's definition of health refers to the "well being" of individuals. The odours resulting from the blowout certainly affected the well being of some individuals, in some cases to the extent of causing nausea.

8.5 If similar blowouts occur in future, a control centre should be established for co-ordination of activities and communications with the public. There should also be a pollution response team formed to adequately monitor for pollutants and the results should be made available to the public.

9 Health Unit Association of Alberta

This group did not present evidence, but in the closing argument took the following position:

9.1 The Medical Officer of Health and local health authorities should be involved in planning for emergencies such as the Lodgepole blowout and their jurisdictional responsibilities should be more clearly defined.

9.2 A protocol should be established and financial support should be made available so that health data gathering and research work could commence immediately when future blowouts occur.

10 Alberta West Central Health Unit (Health Unit)

Dr. Bayliss presented the following evidence on behalf of the Health Unit:

10.1 The Health Unit was aware of the blowout within a day of its occurrence and was in daily contact with the ERCB and other involved parties.

10.2 The question of intentionally igniting the well was discussed as early as 19 October 1982. The understanding was that the well would have been ignited if evacuation levels were encountered at Drayton Valley.

10.3 Medical clinics were held at Drayton Valley and Lodgepole during the period of the blowout. Certain physicians in the general area suggested that any H_2S health impacts resulting from the blowout were below irreversible levels.

10.4 Better co-ordination of responsibilities is needed in the case of future blowouts. In particular, improved information for the public is an absolute requirement.

11 Environmental Law Centre (ELC)

The ELC did not present evidence, but cross-examined certain witnesses and participated in closing argument. The position taken by the ELC is summarized as follows:

11.1 The inquiry procedure revealed two critical areas of confusion: the first being jurisdiction over environmental matters and human health, the second being responsibility for emergency response planning and actions.

11.2 Most of the environmental studies were conducted by Amoco rather than Government departments and this results in lack of credibility.

11.3 A review is needed of the framework of environmental responsibilities and services in the province.

11.4 Funds should be made available to study the long-term, low-level effects of H_2S.

11.5 Evacuation criteria should be firmly established and up-to-date records of where people live are necessary as part of an emergency response plan when sour gas wells are being drilled.

12 Mr. C. Sams

Mr. Sams is a former long-term oil-field worker with considerable experience on drilling rigs, at responsibility levels up to and including the position of "driller". In this capacity, he would operate the rotary drilling equipment and have direct responsibility for a crew of three to five workers. Mr. Sams' position respecting the blowout can be summarized as follows:

12.1 The drilling industry generally has not taken sufficient precautions respecting the safety of workers.

12.2 OH&S does not have sufficiently trained people to properly understand and adequately inspect drilling rigs.

12.3 Drilling rig crews are often not sufficiently trained in kick-control and blowout prevention procedures to adequately deal with them.

12.4 The ERCB inspection frequency for rigs is not sufficient, nor is the detail of the inspections. Additionally, rigs should be inspected without prior warning and during the night and weekends as well as normal working weekday hours.

12.5 The personnel on the rig did not react properly in every respect when the problems were encountered on the evening of 16 October and morning of 17 October. Better attention to and knowledge of the drilling records (eg, geolograph charts), the mud system, kick-control procedures, and procedures for tying down drill pipe to prevent it being forced out of the hole could have prevented the blowout.

12.6 The inquiry did not receive sufficiently detailed information to understand the cause of the blowout.

13 Other Involved Organizations

Inquiry Counsel, on behalf of the Panel, called witnesses from several organizations that had involvement in the incident but which had not registered as participants. These included the Town of Drayton Valley, the County of Parkland, and the Royal Canadian Mounted Police (RCMP). Their respective positions are set out in the following:

13.1 Town of Drayton Valley (Town)

13.1.1 The Town could have, if necessary, declared an emergency within minutes. This was not considered necessary as Town officials did not believe the situation such that an emergency evacuation would be needed. For this reason, residents were not informed of a possible need for evacuation.

13.1.2 Amoco and local Government departments appeared to be addressing the matter in a satisfactory manner and kept Town officials reasonably aware of the situation. Two monitors within the town were installed by Amoco to ensure that H_2S concentration levels were known and could be reacted to as appropriate.

13.1.3 Daily news releases describing the up-to-date situation should have been issued by Amoco and the ERCB.

13.2 County of Parkland (County)

13.2.1 The County was not satisfied with the degree of co-ordination. It should have been involved at the outset and kept up to date.

13.2.2 The public should have been made aware of any evacuation plans that existed.

13.2.3 The County is a knowledgeable party without a vested interest in the 13-12 blowout and, as such, could have provided information to the public in a credible manner.

13.3 Royal Canadian Mounted Police (RCMP)

13.3.1 The RCMP learned of the blowout from the ERCB on 17 October.

13.3.2 An appropriate arrangement existed between Amoco and the RCMP regarding notification and evacuation of the public. The RCMP assisted in the notification of Lodgepole residents on 18 October and would have been available to do the same for the town of Cynthia if requested.

13.3.3 Road-blocks to prohibit entry by the public to the well-site area were set up and manned by the RCMP or Amoco through an arrangement agreed to by the police.

13.3.4 The co-ordination of the incident was generally acceptable, but better communication with the public should have taken place.

14 The General Public

Informal sessions of the inquiry were held in both Drayton Valley and Edmonton to allow members of the general public to express their views regarding the blowout. The number of individuals that came forward to express their views was limited and the following is a summary of the positions they took:

14.1 Many individuals experienced health symptoms during the blowout, many youngsters were absent from school, and missed work-time appeared to be greater than normal. Had the inquiry taken place closer to the time of the blowout, more people would likely have appeared.

14.2 Animals suffered from runny eyes, breathing problems, and scours, and generally experienced weight losses during the period of the blowout.

14.3 Government should be doing the monitoring, not the oil company, and the government must keep the public informed. For example, the public should have been given reasons as to why the well was not intentionally ignited. The ERCB must take steps to see that similar instances do not occur in future.

APPENDIX 5 LODGEPOLE BLOWOUT INQUIRY — PHASE 2 REPORT

Decision D 84-5

Lodgepole Blowout Inquiry — Phase 2.

Sour Gas Well Blowouts in Alberta;
Their Causes, and Actions Required to
Minimize Their Occurrence

Issued 25 April 1984

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

LODGEPOLE BLOWOUT INQUIRY — PHASE 2. SOUR GAS WELL BLOWOUTS IN ALBERTA; THEIR CAUSES, AND ACTIONS REQUIRED TO MINIMIZE THEIR FUTURE OCCURRENCE

Decision D 84-5
Proceeding 830007

1 EXECUTIVE SUMMARY

The inquiry into the Lodgepole blowout[1] was undertaken in two phases; Phase 1 being an inquiry into the causes and impacts of the blowout of the AMOCO DOME BRAZEAU RIVER 13-12-48-12 well (13-12 well), and Phase 2 being an inquiry into improvements that might be made in drilling operations in order to reduce the possibility of another such blowout occurring in Alberta.

Several important recommendations were made during the second phase of the inquiry and the Inquiry Panel (Panel) is convinced that while the Alberta blowout record is comparable to that in other jurisdictions, it can be improved. Furthermore, because drilling is on-going, the Panel believes that improvements should be instituted as quickly as possible to reduce immediately the potential for another "Lodgepole". It has, therefore, decided to complete and publish its report on the second phase of the inquiry prior to the completion of its report on the causes and impacts of the blowout of the 13-12 well.

Participation in Phase 2 of the inquiry included representatives from oil and gas industry associations, and several major companies. There was also limited participation from the general public and the Alberta government.

The Panel has reviewed all of the recommendations made and believes that many of them can assist in reducing the number of blowouts in Alberta, particularly blowouts of sour gas wells. While some of the recommendations can only be implemented after research and review, several can be initiated immediately and the Panel has so recommended.

Almost everyone appearing at the second phase of the inquiry agreed that the primary cause of blowouts is human error and the remedy is to reduce that possibility. Immediate steps should be taken, therefore, to improve and increase training and awareness of the potential contributory factors by *all persons* associated with drilling operations. The blowout prevention process must begin with the initial plans for drilling the well and must include the equipment to be used and the special precautions to be taken. All parties must support an improved and comprehensive inspection process to ensure that the equipment, planning, and its execution are fully effective

The Panel has asked the ERCB to implement, as a priority, a program which will impose additional controls in the planning for and drilling of certain critical sour wells. For such wells, the drilling plan and equipment to be used will require ERCB approval. An emergency response plan will also be required.

A review committee will also be formed to identify measures to improve training and awareness with respect to drilling and to improve the planning for, and equipment used in drilling into formations where high pressure hydrogen sulphide (H_2S) gas may be encountered. Human error as a factor in drilling operations will be reviewed to determine what actions to reduce it are feasible. The inspection of drilling rigs will be addressed by the committee with a view to increased inspections prior to critical drilling operations, and the potential for the development of an Alberta code of practice for drilling will be examined.

Some activities are already underway and others will be implemented following the release of this report. Time limits for reporting to the ERCB by the review committee have been set to ensure that results are obtained respecting the improvements required. These findings and others are more specifically described in Section 6 of the report

The Panel expects that implementing the recommendations arising out of Phase 2 of the Lodgepole Inquiry will lead to improved oil and gas well drilling practices in Alberta which will reduce the number of well blowouts, especially sour well blowouts.

2 INTRODUCTION

2.1 Background

The well, AMOCO DOME BRAZEAU RIVER 13-12-48-12, located in legal subdivision 13 of section 12, township 48, range 12, west of the 5th meridian, near the hamlet of Lodgepole, Alberta, blew out of control from 17 October 1982 to 23 December 1982 — a total of 67 days. On 14 January

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[1] A glossary of oilfield terms is attached as Appendix 1.

1983, the Energy Resources Conservation Board (ERCB) announced that an inquiry would be held ". . . to determine the facts surrounding the Lodgepole gas well blowout . . .". Three pre-inquiry meetings were held to establish terms of reference and other details of how the inquiry should proceed. The terms of reference were issued on 5 May 1983. The inquiry was separated into two phases — the first to deal specifically with the blowout of the 13-12 well and the second

> ". . . to inquire into, report upon, and make such recommendations as are necessary or advisable in relation to the causative factors of sour gas blowouts in Alberta and actions that can be reasonably taken to minimize the possibility of future occurrences."

This report pertains to Phase 2 of the inquiry.

2.2 Procedural Decisions

The inquiry was separated into two phases in order to facilitate industry participation in that portion of the inquiry dealing with the broad question of blowouts in the Province as a whole. For the same reason, the Panel agreed to move the venue for Phase 2 from Drayton Valley to Calgary. It was also decided to conduct separate registrations of participants for Phase 1 and Phase 2, to hold separate final arguments, and to issue separate reports. The Panel also decided there would be one continuous record for both phases of the inquiry and as a result, evidence filed and heard in Phase 1 would, where appropriate, apply to Phase 2, and vice versa.

2.3 The Inquiry

The Panel consisted of V. Millard, Inquiry Panel Chairman, and Panel Members, G. J. DeSorcy, P.Eng., F. A. Herbert, M.D., J. W. Markham, M.B., N. A. Strom, P.Eng., and R. S. Weaver, Ph.D. Participants in the inquiry are listed in Appendix 2.

Phase 1 of the inquiry was held from 1 November 1983 to 15 February 1984 in the town of Drayton Valley, Alberta, except for one day in Edmonton, Alberta, on 9 December 1984. Phase 2 was held from 20 February 1984 to 2 March 1984 in Calgary, Alberta.

2.4 Sour Gas Wells in Alberta

Early in 1983, the Panel commissioned F. G. Bercha and Associates Limited to analyse the risk of sour gas drilling blowouts in Alberta. Bercha found that the number of sour gas wells drilled in Alberta was too low to permit meaningful statistical study as a separate group. Bercha found that approximately 1 per cent of the 20 000 wells drilled in the three years 1980 to 1982 were sour. In separate evidence, the ERCB staff testified that of the 220 sour wells drilled in 1980-1982, 160 were classified as sour oil wells and 60 as sour gas wells. Of the 60 sour gas wells only 25 produce gas containing more than 1 per cent H_2S.

Bercha found it necessary to analyse the data for all wells, whether sweet or sour, oil or gas, and then modify its findings to reflect the frequency of occurrence of H_2S. Bercha made no distinction between oil and gas wells.

3 WELL BLOWOUTS IN ALBERTA

3.1 Risk of Blowouts

Blowouts occur as a result of a failure to control a "kick". Based on a review of the ERCB's computer records and document files, Bercha found that of the 4000 to 6000 wells drilled each year in Alberta

- 1 in every 29 (3.5×10^{-2}) would experience one or more kicks,
- 1 in every 2900 (3.5×10^{-4}) would experience a blowout, and
- 1 in every 62 500 (1.6×10^{-5}) would be a sour gas well blowout.

The above estimate of the sour gas well blowout rate is based on the proportion of sour wells in the total number of wells drilled and the assumption that sour wells are no more difficult to drill than sweet wells. However, the Panel has reviewed the ERCB data and found that 6 sour gas well blowouts were experienced while drilling 51 000 wells from 1974 to 1983. This is 1 in every 8500 (1.2×10^{-4}). The total number of sour gas wells drilled was 1030; therefore, the rate of sour gas well blowouts per sour gas wells drilled is 1 in every 172 (5.8×10^{-3}).

Bercha testified that the higher blowout rate actually experienced for sour gas wells is the result of a number of factors:

- sour gas is highly corrosive and equipment failures are more likely in the presence of sour gas,
- in any potentially sour environment, blowout prevention procedures are complicated by the need for drilling crews to take greater precautions, and
- deeper wells, whether sweet or sour, experience a much greater rate of drilling problems, and sour gas is found only in the deeper formations.

From the ERCB's records of the wells drilled in the period 1980-82, Bercha was able to relate the occurrence of a kick (ie, the first stage of a potential blowout) to the drilling operation in progress. He found that the 703 kicks reported occurred

40 per cent while tripping out,
33 per cent while drilling,
13 per cent while circulating,

7 per cent while tripping in,
3 per cent while coring,
2 per cent while testing, and
2 per cent while other operations were in progress.

A brief description of the blowouts in the last 10 years is provided in Appendix 3.

A review of the circumstances leading to these blowouts reveals that they occurred

43 per cent while tripping out,
33 per cent while drilling,
10 per cent while running casing,
5 per cent while circulating,
5 per cent while logging, and
5 per cent while coring.

These findings are very similar to those reported by Bercha, even though they are for blowouts rather than kicks, are for a different time period, and are for a much smaller number of occurrences.

3.2 Cost of Blowouts

Confer Consulting Ltd. was engaged by the Panel to develop estimates of the costs associated with blowouts for a range of consequences identified as minor, moderate, and severe. These were to reflect the consequences defined as sour gas well blowouts lasting 1 day, 6 days, and 100 days, respectively. Equipment losses and other consequences were assumed to escalate progressively with the duration of the blowout.

Confer estimated that the cost of a severe sour gas well blowout could be 50 million dollars, of which one half would be the cost of lost, delayed, or deteriorated hydrocarbon production. A moderate blowout could cost 2 million dollars, of which 0.5 million dollars was associated with hydrocarbon losses. A minor blowout could cost less than 200 thousand dollars with negligible hydrocarbon losses.

It should be noted that these costs do not include many intangible and unquantifiable social costs such as nuisance impacts and the feelings of anxiety on the part of the general public.

With potential costs of the magnitude estimated above, the Panel believes certain measures to reduce blowouts are justified, particularly for sori wells where the impacts would be greatest. For instance, the Panel believes it would be beneficial for industry to direct funds into research concerning equipment and materials on a continuous basis and to support efforts to reduce blowouts.

3.3 Alberta Drilling Performance

3.3.1 Blowout History

The frequency of well blowouts in Alberta for the past 25 years is presented in Figures 1 and 2. Figure 1 shows the number of wells drilled and the number of blowouts. Figure 2 shows a 3-year moving average of the number of blowouts per well drilled. It reveals a low in the number of blowouts per well drilled in 1963, a rapid rise to a peak in 1969, followed by a decline to the present time. No evidence was heard to explain the marked variation in the blowout rate in the 1960s, however, the Panel is aware that the Pembina-Cardium area was drilled in the late 1950s and early 1960s, and it is a low permeability sweet oil pool which would not likely result in blowouts. In contrast, the Zama-Keg River area of northwest Alberta was drilled in the late 1960s, and it is an area prone to lost circulation and other drilling problems.

The blowout rate dropped substantially in the early 1970s and has further declined in recent years to one blowout for every 2900 wells drilled (a rate of 3.5×10^{-4}). Several participants credited the decline to improved equipment and improved training of rig personnel. CAODC noted that the first complete blowout prevention course designed by industry was presented in 1968. In 1971, well control training facilities were established at Golden Spike.

3.3.2 Comparison to Other Jurisdictions

Many of the witnesses who appeared in Phase 2 had drilling experience in other parts of the world — either in other provincial or federal jurisdictions within Canada or in other countries. Although they provided no details, the majority of witnesses examined on this subject said they believed Alberta's blowout record was comparable to that in other jurisdictions.

Bercha testified that, on the basis of other blowout studies it had done and the literature it had reviewed, Alberta's recent blowout rate of 3.5×10^{-4} was remarkably close to the estimated world average of 3.9×10^{-4} for land-based wells.

3.3.3 Rig Inspections

Drilling equipment is inspected separately and regularly by operators, contractors, and ERCB staff. Current regulations do not require operators or contractors to file their inspection reports with the ERCB. The matter of rig inspections is dealt with further in Appendix 4.

ERCB staff testified that inspections of drilling rigs had been carried out by its staff on 33 per cent of all wells drilled during the years 1979 to 1983. The staff found that 47 per cent of the rigs inspected were unsatisfactory in some respect. Of the 47 per cent found unsatisfactory, 83 per cent had one or more serious deficiencies. A serious deficiency was

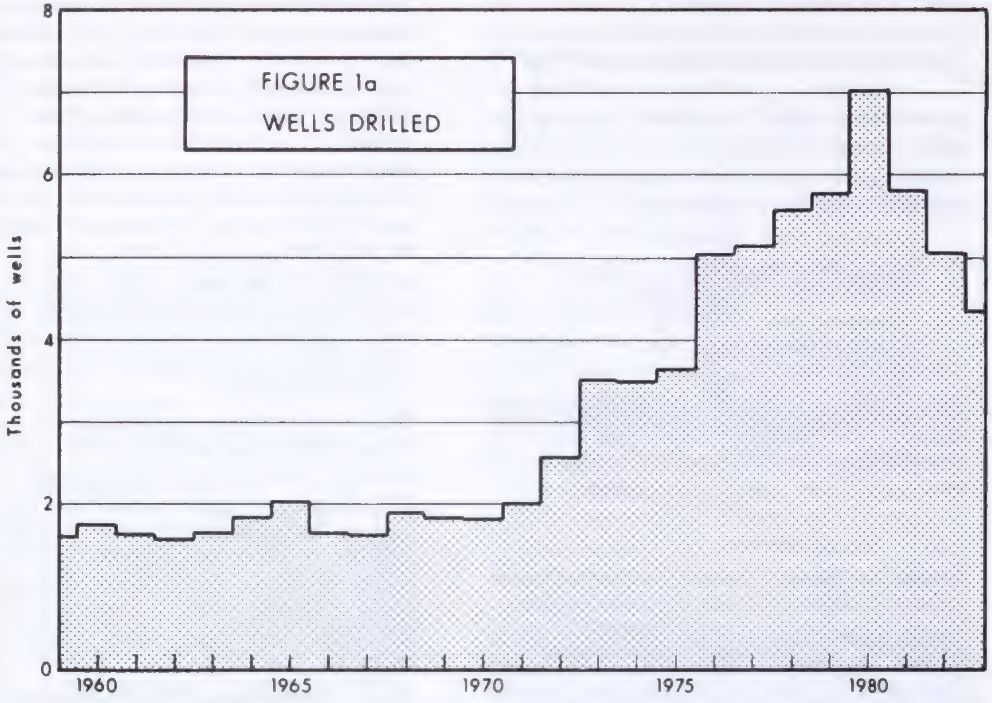

FIGURE 1a
WELLS DRILLED

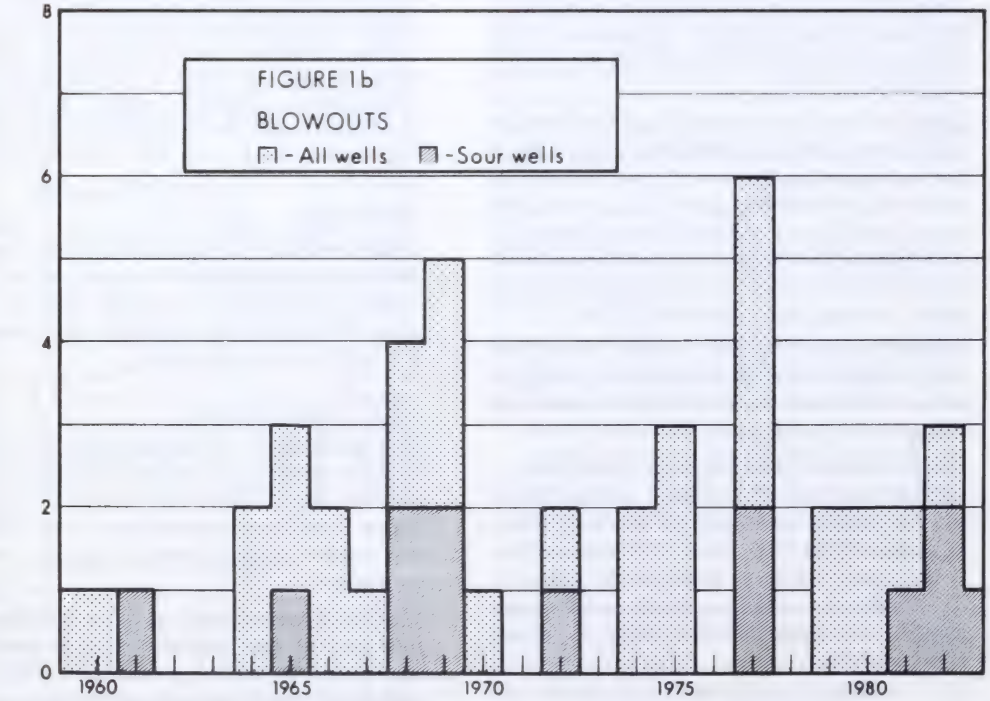

FIGURE 1b
BLOWOUTS

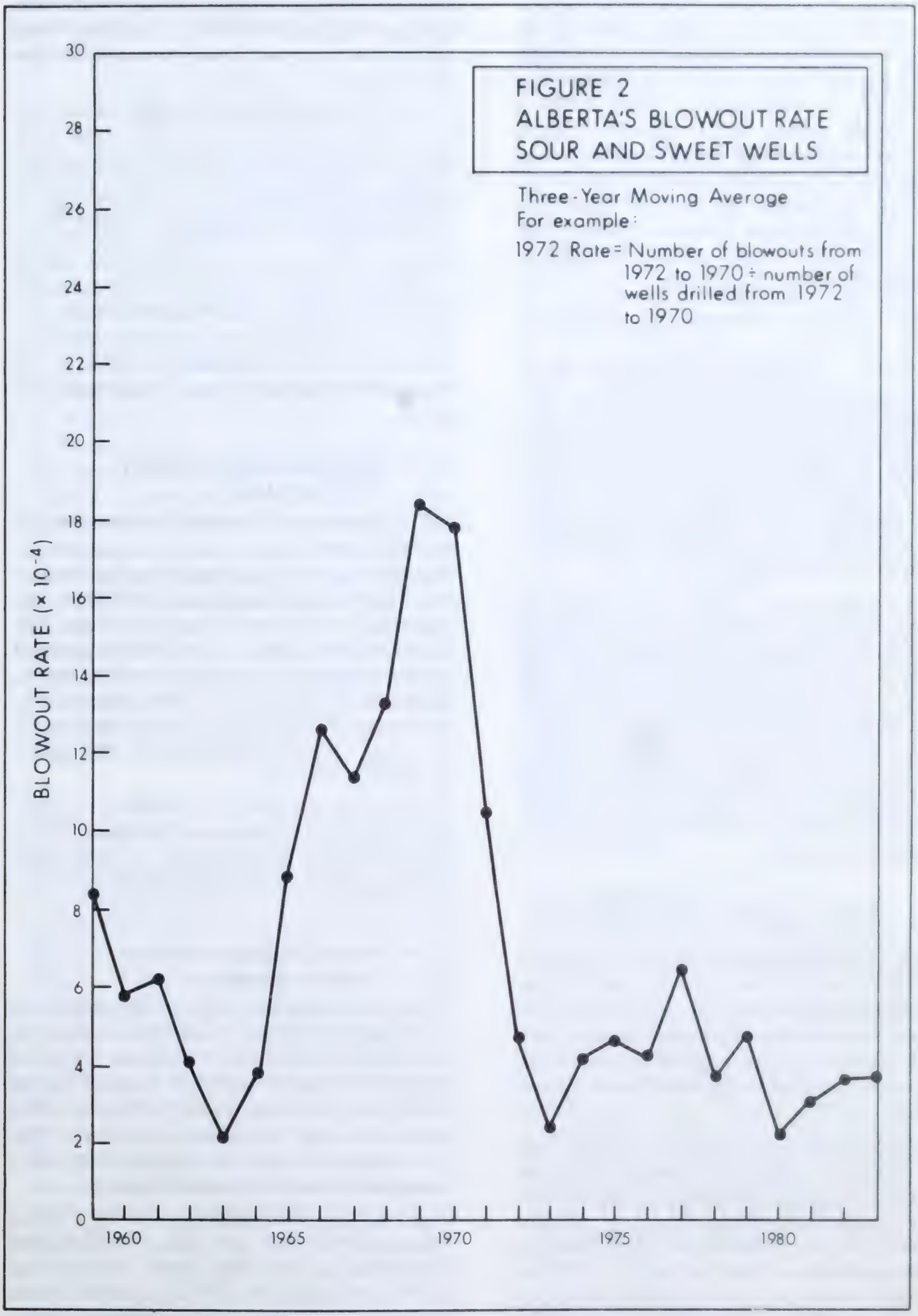

FIGURE 2
ALBERTA'S BLOWOUT RATE
SOUR AND SWEET WELLS

Three-Year Moving Average
For example:
1972 Rate = Number of blowouts from 1972 to 1970 ÷ number of wells drilled from 1972 to 1970

described as a matter that might hinder well control under certain circumstances. One of the circumstances that would have to exist in order for the serious deficiency to represent an immediate danger is that the rig would have to be drilling in or approaching a porous formation where a flow of fluid into the wellbore would be possible. Indeed, only 4 per cent of the rigs found unsatisfactory were judged to be in immediate danger to the extent that they were immediately shut down and further drilling progress prohibited until the deficiency was rectified. A further 16 per cent required immediate correction but were not shut down.

Serious concern was expressed as to whether the ERCB staff definition of serious deficiencies was appropriate. The ERCB staff emphasized that the definitions had been developed to direct its available inspection staff to new rigs, rigs with poorer records, and those in trouble prone areas, and not for the purpose of measuring the overall adequacy of rigs. The staff suggested that it and industry representatives should review the definitions and inspection data and prepare a new set of statistics which would reflect overall rig adequacy.

The Panel agrees this should be done and has so recommended to the ERCB. A committee is being appointed by it, including a representative on behalf of the public, and a report, which will be made public, is expected within two months. The committee is being asked to review the adequacy of inspection coverage, not only by the ERCB but also by industry, and to recommend ways in which the inspections and resulting reports could be better co-ordinated. The letter inviting participation on the committee is attached as Appendix 4.

3.4 Scope for Improvement in Incidence of Blowouts

Figure 2 illustrates that there has been a wide variation in well blowout rates over the last 25 years. Although most participants stated they believed an irreducible minimum existed because the basic problem is human error, none suggested that the low rate experienced in the last few years could not be reduced further.

Bercha concluded that all blowouts were the result of the failure to control a kick, and that failure was most often the result of human error. Several of the other participants agreed that human error was often involved, but many believed that a combination of human errors and other factors (eg, equipment failure, weather conditions, unpredictable geological conditions) played a combined role in causing blowouts. Bercha concluded that the greatest potential for reducing the blowout rate was by increased enforcement of the drilling regulations, followed by improved training of drilling personnel. While some participants agreed with Bercha, the majority stated they believed improved training would be the most beneficial.

The Panel concludes that the frequency of blowouts can be reduced further and in view of the much higher blowout rate for sour wells, believes that emphasis should be placed on that category. However, because of the human factor it is unreasonable to expect elimination of all blowouts. Improving the training of all persons involved with the drilling operation will most likely reduce blowouts and adjustments must be made to other factors that contribute. Since the potential for blowouts will always exist, industry will have to maintain its vigilance. The Panel will be be addressing these matters later in the report.

4 RECOMMENDATIONS BY PARTICIPANTS

4.1 Primary and Secondary Recommendations

The participants presented many recommendations and there was considerable agreement on most of these. The Panel has classified some of these recommendations as "primary" because they deal with matters of major importance which should be addressed as soon as possible. Other recommendations of less immediate importance have been classified as "secondary". These relate to matters which generally would not be critical in terms of reducing the likelihood of blowouts.

The Panel has also identified a number of "other" recommendations that are beyond the terms of reference for Phase 2 of this inquiry, or may require action by agencies other than the ERCB.

4.2 Recommendation to Form a Review Committee

A recommendation that received wide support was that a joint ERCB/industry blowout prevention review committee be established. Participants stated that many of the matters dealt with required detailed technical and economic review, and that for others there was a lack of information available. They recommended that these be referred to the review committee for detailed assessment or study.

The Panel agrees that there is a need for a review committee. The committee should be made up of representatives of CAODC, IPAC, CPA, and the ERCB and representatives of the public and certain Government departments should be invited to participate on selected sub-committees of particular interest to them.

In subsequent sections of this report the Panel will identify those matters that the review committee should examine, indicating the urgency or time constraints.

5 PANEL VIEWS ON SPECIFIC RECOMMENDATIONS

5.1 Primary Recommendations

5.1.1 Critical Sour Well Definition

Participants in the inquiry generally agreed with the establishment of a category of "critical sour wells" that would recognize:

(a) the location of the well,
(b) the estimated maximum H_2S concentration, and
(c) the estimated maximum flow rate.

Special precautions and blowout prevention controls would then be practised at these wells.

The Panel agrees that there is considerable merit in defining and imposing special controls on critical sour wells. It also saw considerable urgency in this respect and consequently recommended that the ERCB take immediate action. A draft Interim Directive defining critical sour wells and setting special requirements for them is being issued simultaneously with this report and is attached as Appendix 5. It will be used on an interim basis for approximately six months. The review committee and representatives of public interest groups and Government departments will be asked to review and comment on it. A revised long-term policy will then be instituted.

5.1.2 Training

Almost all participants suggested increased attention to the training of rig crews, including more hands-on training during blowout prevention drills, with particular focus on training for the driller and those rig workers that report to him. Suggestions included certification of both the drilling foreman and rig manager, establishment of a third line blowout prevention certificate, specific training for the driller and the rig workers he supervises (derrickman, motorman, and roughnecks), an H_2S awareness course for crews, and an increase in management awareness of drilling practices and the consequences of failure.

The Panel believes that human factors are very significant in terms of preventing blowouts. For this reason, increased training could be a significant and effective factor in reducing blowouts and the Panel agrees with the participants that it should be pursued. In addition to the increased training in the conventional sense, eg, blowout drills, the Panel believes that an analysis should be made of how human errors cause blowouts, and what preventative action might be taken.

The Panel suggests that the matter of training should be a priority item and should be handled within six months of the formation of the review committee. A further analysis of human factors which cause blowouts should be pursued by the committee, or perhaps a sub-committee, over the longer term. Factors such as education and experience, age, health, safety attitudes, hours of work, turnover rates, fatigue, and boredom are examples which would be included in the terms of reference of the committee. An opportunity to comment on the recommendations of the committee should be given to Government departments such as Labour, Manpower, and the Workers' Compensation Board, to the public, and representatives of training services.

5.1.3 Increased Enforcement

The participants at the inquiry were divided with respect to increased enforcement of regulatory controls. One suggestion involved the suspension of the crew members' blowout prevention (BOP) certificates and shutting down well operations for infractions at well sites. Participants encouraged the ERCB and operators to ensure that blowout prevention drills were done properly and recorded.

The Panel agrees and has asked the ERCB to increase enforcement, particularly on critical sour wells and with respect to blowout prevention drills. Care should be taken in distinguishing between minor and serious infractions and the latter should result in suspension of rig operations until corrective action is taken. The Panel recommends that the review committee, with input from appropriate Government departments, consider the factors involved in the suspension of BOP certificates.

5.1.4 Inspection

The participants were supportive of increased ERCB and operator rig inspections, particularly with respect to critical sour wells at critical times during drilling.

The Panel agrees there is a need for increased inspection of wells drilling into abnormal pressure and high H_2S concentration formations and believes that inspection should take place prior to drilling critical portions of the well. The draft Interim Directive, Appendix 5, sets this out as a particular requirement for critical sour wells. The Panel is aware that the ERCB is analysing its rig inspection policy with respect to arrangements for rigorous and more frequent inspections of wells that may encounter sour gas.

5.1.5 Supervision

A strengthening in the number and experience of the on-site supervisory personnel by operator and contractor at wells drilling into sour formations was suggested by several participants. Specific suggestions included a special team for high pressure H_2S wells, a minimum 5-man crew on all sour wells, supervisors on 12-hour shifts for critical wells at critical times, and increased training for operator and contractor representatives.

The Panel agrees that supervision should be enhanced for drilling critical sour wells with particular attention to the critical drilling periods. The draft Interim Directive requires, for critical sour wells, a minimum 5-man crew, experienced supervisors on maximum 12-hour shifts, and additional specialized safety personnel on site at all critical drilling periods.

5.1.6 Special Drilling Equipment

Unanimous support was given for the formation of an ERCB/industry committee to review a multitude of equipment-related concerns with particular emphasis on equipment for sour gas drilling. The most important of these items were the improvement of drilling monitors and kick detection equipment, degassers, shear rams, inside BOPs, drill pipe, the need for H_2S-resistant equipment, and the location of the lower drilling spool.

The Panel is in agreement that the review committee should consider drilling equipment with emphasis on high pressure H_2S requirements. It believes the committee should bring forth recommendations as they are formulated and that the most important items should be dealt with in 6 to 12 months.

5.1.7 Information Exchange

The publication of the causes and circumstances of blowouts, drilling rig deficiencies found by ERCB inspections, and the gathering of drilling data from world-wide sources into a central location were suggested and generally supported by the participants.

The Panel agrees with the suggestions but notes that prior to the publication of drilling rig deficiencies, analysis and evaluation is required to ensure the data is meaningful. The Panel understands that the ERCB will, where possible, publish a report outlining the cause and circumstance of blowouts in Alberta. Appendix 3 is intended to assist in this regard. The Panel will recommend that the review committee establish a format for the gathering of drilling and other relevant data with particular emphasis related to drilling high pressure H_2S formations.

5.1.8 Site-Specific Emergency Response Plans

Some participants suggested that there should be site-specific emergency response plans for the drilling of critical sour hydrocarbon wells.

The Panel considers it essential for site-specific emergency response plans to be in place prior to the drilling of critical sour wells. This is reflected in the draft Interim Directive included as Appendix 5. The plan must include information as to how the public would be advised, protected, and evacuated if necessary, in the event of a blowout, and the plan must be discussed with the public. Emergency response plans were discussed extensively during Phase 1 of the inquiry and the Panel will be addressing the matter further in the Phase 1 report.

5.1.9 Drilling Plan

Participants generally agreed that drilling and geological data should be exchanged in order to improve drilling programs, but they recognized the constraints imposed by the confidential nature of geological data. Some participants were prepared to provide the ERCB with a copy of the drilling program, or a summary of it, and most indicated they already provide a copy to the drilling contractor.

The Panel urges operators to exchange geological information so that drilling programs can be designed in an optimum fashion for drilling into abnormal pressure and H_2S formations. As indicated in Appendix 5, a general description of the drilling plan and equipment to be used to drill a critical sour well must be submitted to, and approved by, the ERCB prior to the spudding of the well. The Panel will recommend that the review committee consider a method, suitable to industry and the ERCB, of exchanging geological information to assist in the development of drilling plans.

5.1.10 Mud System Design

The position taken by most participants was that mud system design should not be regulated, intentionally underbalanced mud programs should be eliminated, and appropriately safe mud programs should be followed for drilling into H_2S formations. Participants also commented on the importance of spare mud supply and differed in their opinions with respect to the use of stand-by tanks.

The Panel agrees that mud system design is a complex technical matter that must relate to the variable geological and drilling conditions at each well. It therefore does not lend itself to regulation. Nonetheless, very careful attention should be given to mud system design, particularly for high pressure H_2S formations with appropriate consideration being given to anticipated geological conditions in critical zones (pressure, permeability, formation fluids), the capacity of mud tanks, mud pH control, high speed mixers, and H_2S scavengers. The Panel recommends that this item be included for consideration by the review committee, including the possibility of a code of practice for mud system design.

5.1.11 Alberta Code of Practice for Drilling

The development of an Alberta code of practice for drilling with emphasis on sour gas wells was favoured by some participants. It was suggested that certain of the current regulations could be incorporated into a code of practice along with matters such as drill string design, drilling procedures, material and equipment specifications, and requirements for H_2S resistant blowout prevention equipment.

The Panel believes that the possibility of a code of practice for drilling should be considered by the review committee as a high priority.

5.2 Secondary Recommendations

5.2.1 Well Ignition

The participants suggested that a blowout well should not be automatically ignited because of the resulting damage to well control equipment, which in turn, would likely lengthen the duration of the blowout. It was suggested that the operator be given some time in which to formulate a control plan before ignition is considered.

The Panel agrees that a blowout well should not be automatically ignited in every instance but believes, because of the potential impact of certain wells at certain locations, that immediate ignition may be a necessity in some cases. The decision procedure as to whether the well should be intentionally fired in case of a blowout should be part of the emergency plan for sour wells. The Panel notes that because of the potential consequences which may occur, other Government departments and the public should be involved in determining ignition criteria. The Panel understands that the ERCB will initiate discussion in this regard with industry, Government, and the public. In the interim, if deemed appropriate by the ERCB, specific well licences will include a condition that the well be immediately ignited in case of a blowout.

5.2.2 Winter Drilling

Some participants expressed concern regarding a higher incidence of well problems, including blowouts, during winter months. Others suggested the statistics were being misinterpreted, and in any case any problem that existed could be eliminated by ensuring that the equipment was adequate for winter drilling.

The Panel believes that winter drilling can be conducted in a safe and effective manner providing the operator and contractor are sufficiently careful to ensure the adequacy of equipment and procedures to account for the severity of conditions.

The Panel recommends that the review committee consider the development of practical guidelines for equipment capabilities for winter drilling and the incorporation of them in any Alberta code of practice for drilling.

5.2.3 Contractors' Responsibility

One participant suggested that contractors should be given increased responsibility for the consequences of well control problems. The industry participants were united in their opposition to changing the existing contractual arrangements between the operator and the contractor.

The Panel believes that the responsibility for safe drilling practice must reside with the operator licensed to drill the well. It recognizes and supports the concept that certain requirements be contractually imposed on the drilling company, but does not believe that changes should be made to the existing situation where the operator has final responsibility.

5.2.4 Blowout Insurance

Insurance against blowouts was suggested to be far more expensive than small operators could afford. However, it was indicated that most major operators would have either blowout insurance or other corporate insurance that would cover a blowout incident.

The Panel is concerned that an uninsured operator with limited resources could have a major blowout which, in turn, could result in major economic impact to be covered by the public purse. The Panel understands that the ERCB intends to investigate further the need for and availability of blowout insurance and to consider whether it should be a requirement of each licensee.

5.2.5 Blowout Equipment Co-operative

A co-operative pool of blowout control equipment was suggested for use by any operator in the Province to assist in well control operations following a blowout. The CPA said it has maintained an equipment co-operative for several years at Golden Spike, Alberta, but the equipment has only been called out on three occasions and has never been used. This is apparently because the blowout control experts usually insist on using their own equipment.

Although the Panel can understand that blowout control experts in their very high risk work would want to use familiar equipment, it also believes that a pool of some blowout control equipment could be maintained and be of assistance to operators. The Panel recommends that the review committee give further consideration to this matter.

5.3 Other Recommendations

5.3.1 Safety

Safety concerns were raised by some participants in the inquiry who questioned the adequacy of the current regulations for breathable air supply on drilling rigs, the training in its use, and safety training for supervisors. Discussion also covered the length of a reasonable workday under stress conditions.

The Panel notes that the question of safety of workers at rig sites is within the jurisdiction of the Occupational Health and Safety Division of the Alberta Department of Workers' Health, Safety and Compensation, but believes that consideration of these matters should be initiated. The Panel will request that the ERCB contact the Occupational Health and Safety Division to initiate discussions on the matters set out in Appendix 8.

6 FINDINGS

Based on the evidence presented during Phase 2 of the inquiry, the Panel finds that

- The Alberta blowout experience appears comparable to that of other jurisdictions and costs vary greatly depending on the blowout severity.
- The Alberta blowout rate has steadily declined since the early 1970s, but sour gas blowouts continue to represent a disproportionate share of the total.
- It is probably not possible to completely prevent blowouts in Alberta but it is possible to reduce the frequency of blowouts by appropriate action.
- It is particularly important to develop and implement special measures that would be designed to prevent the blowout of "critical sour wells" and an ERCB draft Interim Directive is being issued for that purpose. It defines a critical sour well and requires approval by the ERCB, prior to spudding, of a general drilling plan, the equipment to be used, and an emergency response plan. Experienced supervisors and crews and increased inspections are also required.
- Industry and the ERCB need to work co-operatively to achieve the foregoing objectives and a review committee will be established with terms of reference and review items as summarized in Appendices 6 and 7 and referred to later in this section.

Some of the specific findings of the Panel are as follows:

- Addressing the role of human factors in preventing blowouts, improvements in crew training, rig inspection and reporting, drilling plans, mud system design, kick detection and response, and suspension of unsatisfactory rigs are likely to reduce blowouts and will be considered by the review committee.
- Improvements in equipment for H_2S drilling, with emphasis on blowout prevention equipment, drill pipe and degassers, will assist in reducing blowouts and will be considered by the review committee.
- Site-specific emergency response plans must be in place prior to drilling critical sour wells and the plans must reflect input from Government departments and the public.
- Exchange of information regarding rig inspections, blowout causes and circumstances, and drilling practices will assist in reducing blowouts and the most appropriate manner of doing this should be considered by the review committee.
- Criteria for ignition of blowout wells must be established with input from industry, Government, and the public. In the meantime, well licences for some wells in particular circumstances may include a condition for immediate ignition in the event of a blowout.
- Development of a code of practice for drilling, with emphasis on sour gas requirements, should be considered.
- The regulations regarding emergency breathing apparatus, air supply, and the safety of rig personnel need to be reviewed and the ERCB will initiate discussions with Alberta Workers' Health, Safety and Compensation.

ISSUED at Calgary, Alberta on 25 April 1984.

LODGEPOLE BLOWOUT INQUIRY PANEL

V. Millard
Inquiry Panel Chairman

J. W. Markham, M.B.
Panel Member

G. J. DeSorcy, P.Eng.
Panel Member

N. A. Strom, P.Eng.
Panel Member

F. A. Herbert, M.D.
Panel Member

R. S. Weaver, Ph.D.
Panel Member

APPENDIX 1 GLOSSARY OF TERMS

blooey line — the discharge pipe of a well being drilled with air as the drilling fluid.

blowout — an uncontrolled flow of gas, oil, or other well fluids into the atmosphere

blowout preventer (BOP) — the valve-like equipment attached to the casing at a drilling rig to prevent a blowout.

certificate (first and second line) — certificates issued by the Petroleum Industry Training Service in blowout prevention and kick control procedures.

condensate — that part of natural gas that is liquid at normal atmospheric conditions.

BOP stack — the combination of valve-like devices, piping, and other fittings attached to the casing at a drilling rig.

casing (surface, production) — the steel pipe placed in a well to prevent the collapse of the hole and provide a conduit for fluids during the drilling and producing phases.

circulating — the pumping of drilling fluids down the drill pipe, out through the drilling bit, up the annulus, and back to the mud tanks.

coring — a drilling operation which uses a special bit to produce a cylindrical sample or core of the rock penetrated.

degasser (mud-gas separator) — a device which removes formation gas and air from drilling mud.

derrickman — the member of the rig crew who normally handles the upper end of the drill pipe from a position up on the derrick. He is also responsible for maintaining the drilling mud.

directional survey — a procedure to measure the direction and amount that a wellbore has deviated from the vertical.

diverter — a device used in air drilling which conducts the return air and drill cuttings from the top of the well to the flare pit.

driller — the member of the rig crew who operates the rig controls and is responsible for the rig and crew for one of the two or three shifts operating each day.

drilling — the rotating of the drill pipe and bit and the circulating of drilling mud to cause penetration of formations.

drilling program — a document prepared by the licensee of the well which contains instructions, diagrams, and other pertinent information and is the approved procedure for drilling the well.

drilling spool — a spacer between components of the BOP stack, containing valved outlets.

drill pipe — the heavy seamless pipe used to rotate the drilling bit and circulate the drilling fluid.

fishing — to recover equipment such as broken drill pipe that has been lost in the wellbore.

formation — a subsurface layer or deposit that is composed throughout of substantially the same kind of rock.

H_2S scavenger — a material that deactivates any H_2S entering the wellbore.

hydrostatic pressure — the pressure exerted by a column of fluid such as the drilling mud in the wellbore.

inside BOPs — equipment designed to prevent blowout fluids from escaping up the inside of the drill pipe.

isopleth — an imaginary line surrounding a point of potential contaminant release, formed by joining points of equal contaminant concentration (similar to a contour line).

kick — the flow of gas, oil, water, or other formation fluids into the wellbore.

APPENDIX 1 (continued)

lost circulation	— the loss of drilling fluid from the wellbore into a permeable formation.
motorman	— the member of the rig crew who is responsible for the maintenance of the drilling engines, and who may also work on the rig floor.
mud (drilling)	— the liquid circulated down the drill pipe and up the annulus during drilling.
permeability	— a measure of the ability of fluids to flow through rock.
pH	— the acidity or alkalinity of a fluid; a measure of hydrogen ion activity.
porosity	— the open or void space within a rock.
rig manager (toolpush)	— the employee of the drilling contractor who is normally at the well site and is in charge of the entire drilling crew and drilling rig.
roughneck	— the members of the rig crew who usually work on the rig floor.
shear rams	— a component of the BOP stack that can cut or shear through the drill pipe and form a seal against well pressure.
sour gas	— natural gas containing H_2S in measurable concentration.
spud-in	— to start drilling the wellbore.
swabbing	— to pull the drill pipe up the wellbore too quickly and cause a sucking action within the wellbore.
testing	— a procedure to test the type and quantity of fluids contained in a formation.
tour reports (pronounced ‘‘tower’’)	— the daily record of activities at a drilling rig.
tripping (in/out)	— the process of pulling all the drill pipe out of the hole to change a drill bit or other bottom-hole equipment, and then lowering the drill pipe back into the hole.

APPENDIX 2 THOSE WHO APPEARED AT PHASE 2 OF THE INQUIRY

Participants and Representatives (Abbreviations used in Report)	Witnesses
F. G. Bercha and Associates Limited (Bercha)	F. G. Bercha, P.Eng. B. J. Griffin, P.Eng. R. I. Macdonald
Confer Consulting Ltd. (Confer)	G. M. Engbloom, P.Eng.
K. L. Shaw	K. L. Shaw
Energy Resources Conservation Board staff (ERCB staff) M. J. Bruni	W. G. Remmer, P.Eng. E. F. May B. E. McFarlane
Pembina Area Sour Gas Exposures Committee (PASGEC) D. P. Mallon	K. R. Bissett C. Whitelock
C. Sams	C. Sams
Canadian Association of Oilwell Drilling Contractors (CAODC) J. B. Ballem, Q.C.	P. C. Grigg
Canadian Petroleum Association (CPA) F. R. Foran	I. M. Parker, P.Eng. H. Rath, P.Eng. H. Maciej
Independent Petroleum Association of Canada (IPAC) D. O. Sabey, Q.C. B. K. O'Ferrall	W. A. Elser, P.Eng. J. K. Farries, P.Eng.
Canterra Energy Ltd. C. P. MacDonald	W. H. Sawotin, P.Eng. D. Lewis, P.Eng. R. Reid, P.Eng. R. L. Thomas
Dome Petroleum Limited W. M. Smith	H. J. Strain, P.Eng. A. Wichert, P.Eng.
Gulf Canada Resources Inc. J. D. Anderson	L. D. Demosky, P.Eng. D. S. Belczewski F. C. Smith A. E. Wallace, P.Eng.
Petro-Canada Inc. J. W. Gallagher	R. T. McGrath, P.Eng. K. C. Brown W. E. Roeske, P.Eng.
Shell Canada Resources Limited J. D. Courtright	J. R. Tilbe, P.Eng. J. Piaskoski B. Straub, P.Eng.

APPENDIX 2 (continued)

Participants and Representatives (Abbreviations used in Report)	Witnesses
A. Scovil Murray	A. Scovil Murray, P.Eng.
Alberta Government Departments (Government departments) A. R. Watson	
Amoco Canada Petroleum Company Ltd. A. L. McLarty S. E. Lipton	
Inquiry staff R. D. Schachter J. K. Moloney E. J. Morin, P.Eng.	

APPENDIX 3 BLOWOUTS OF DRILLING WELLS* — 1983 TO 1974

Well Name	Date	Duration (days)	Depth (metres)	Loss	Cause
CONGASCOME ET AL SHEKILIE 12-14-118-8 (W6M)	27 Feb 1983	9	1794	610 x 10^3m^3 of gas (2% H_2S)	lost circulation
AMOCO DOME BRAZEAU RIVER 13-12-48-12 (W5M)	17 Oct 1982	67	3067	to be dealt with report	in detail in Phase 1
CANSTAR CALUMET OV 2-24-98-12 (W4M)	11 Feb 1982	13	65	85 x 10^6m^3 of sweet gas; rig burned	unexpected shallow gas sand; no BOPs installed
DOME SULPETRO VALHALLA 8-23-74-9 (W6M)	18 Jan 1982	4	2042	3618 x 10^3m^3 of gas (trace of H_2S)	failure to keep hole full while tripping out followed by BOP failure
HB SHEKILIE 9-16-118-8 (W6M)	18 Nov 1981	4	1548	1613 x 10^3m^3 of gas (0.66% H_2S); rig destroyed	lost circulation
PETROFINA TEST HOLE B5 13-6-51-7 (W5M)	15 May 1981	1	201	28 x 10^3m^3 of sweet gas; fire damage to rig	air drilling with no diverter or BOPs
RENAISSANCE PETMT EDWAND 7-10-61-17 (W5M)	1 Dec 1980	3	648	566 x 10^3m^3 of sweet gas; rig burned	lost circulation; surface casing split
BLAKE ET AL STEEN 10-9-112-1 (W6M)	7 Feb 1980	25	70	no estimate of sweet hydrocarbon loss; major rig fire damage	unexpected shallow gas sand
AMOCO ET AL STEEP 7-28-66-7 (W6M)	22 Nov 1979	3	2338	280 x 10^3m^3 of sweet gas	swabbing with fishing tools
SHELL RANDALL 12-10-81-2 (W5M)	26 Feb 1979	1	484	no estimate of hydrocarbon loss (sweet); fire damage to rig	failure of bleed-off hose on blooey line while air drilling
GULF POC GOLD RIVER 6-18-70-15 (W4M)	20 Dec 1977	2	505	60 x 10^3m^3 of sweet gas	loss of casing cement to weak zone
GAMMA ET AL CESSFORD 6-30-23-10 (W4M)	19 Dec 1977	33	952	1860 x 10^3m^3 of sweet gas; rig destroyed	swabbing while tripping out

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* Blowouts of wells being drilled whether sour or sweet, oil or gas, have been included.

APPENDIX 3 (continued)

Well Name	Date	Duration (days)	Depth (metres)	Loss	Cause
AMOCO PACIFIC BRAZEAU RIVER 7-10-48-12 (W5M)	6 Dec 1977	28	3311	$16 \times 10^6 m^3$ of gas (25% H_2S); rig destroyed	swabbing while tripping out; frozen equipment
WESTCOAST AEC SUFFIELD 8-13-20-8 (W4M)	4 Dec 1977	2	940	$115 \times 10^3 m^3$ of sweet gas	swabbing while pulling drill-stem test tools
DOME LPGS FT. SASK. 15B-14-55-22 (W4M)	13 Mar 1977	2 (hours)	964	$30 \times 10^3 m^3$ of sweet gas	loss of hydrostatic head while repairing mud pump
SHELL 35 WATERTON 12-9-3-30 (W4M)	28 Feb 1977	2	3148	$56 \times 10^6 m^3$ of gas (14% H_2S)	swabbing while tripping out
HUSKY NEERLANDIA 6-30-61-5 (W5M)	18 Jul 1975	1	174	no estimates (sweet gas)	swabbing while tripping out (plugged bit)
CDN-SUP CANSO BADGER 6-3-17-17 (W4M)	14 Mar 1975	4	1145	$2433 \times 10^3 m^3$ of sweet gas	insufficient mud weight
HBOG OIL SANDS Evaluation Hole 7-28-96-11 (W4M)	23 Jan 1975	2	118	$21 \times 10^3 m^3$ of sweet gas; rig destroyed	swabbing while tripping out
SUN CESSLAND JENNER 6-9-22-9 (W4M)	5 Sep 1974	2½	772	$1817 \times 10^3 m^3$ of sweet gas	abnormally high formation pressure
SUNDANCE ET AL DUNVEGAN 10-18-82-5 (W6M)	28 Feb 1974	10½	1510	$1690 \times 10^3 m^3$ of sweet gas	lost circulation; production casing failure

APPENDIX 4 ERCB RIG INSPECTIONS

25 April 1984

Canadian Association of Oil Well Drilling Contractors
Canadian Petroleum Association
Independent Petroleum Association of Canada
Pembina Area Sour Gas Exposures Committee, Mr. K. R. Bissett

ERCB INSPECTIONS OF DRILLING RIGS

During Phase 2 of the Lodgepole Inquiry, ERCB staff presented evidence of the results of its inspections of drilling rigs from 1979 to mid 1983. The evidence indicated that on average, the rigs on 33 per cent of all wells drilled during this period were inspected, 47 per cent were found to be unsatisfactory in some respect, and 83 per cent of the unsatisfactory cases had one or more serious deficiencies.

This evidence resulted in considerable concern and controversy regarding the data, and confusion with respect to how it should be interpreted. The ERCB staff indicated that the statistics had been compiled to assist it in the selection of rigs to inspect, and not for the purpose of assessing the overall quality of drilling operations in the Province. The staff recommended that it and industry representatives should meet to review the inspection forms used by the ERCB as well as the definitions adopted for classifying deficiencies as "serious".

Other participants agreed with this proposal. The Panel also agreed with it, and recommended that this letter be sent. The purpose of it is to invite your association to appoint one or two representatives to a Drilling Rig Inspection Committee under the chairmanship of Mr. Bill Remmer of the ERCB.

The proposed terms of reference of that committee are:

1. Review the inspection frequency policies to ensure that the number of inspections is adequate.
2. Review the ERCB Drilling Rig Inspection Form and the related instruction guides to determine whether they are appropriate for individual rig inspections and also for determining whether the overall state of rigs in the Province is adequate.
3. Review whether the current basis used by the ERCB for classifying inspection deficiencies as "serious" is appropriate.
4. Consider and recommend a procedure whereby the results of ERCB rig inspections might best be communicated to the operators, the contractors, and the public.
5. Consider whether and in what manner the inspections by the operator and contractor might be incorporated into the system.
6. Consider whether a rework of inspection results for 1983, using the appropriate definition of "serious", is possible and appropriate.

The Board considers this to be an urgent matter and seeks your assistance. It has requested Mr. Remmer to complete the review and submit recommendations by 30 June 1984. That report will be a public document.

I would appreciate your advice as to the names of your representatives by 10 May 1984. Attached is a package of information that will be relevant to the committee.

Yours truly,

V. Millard
Chairman

VM/kl
Enclosures

APPENDIX 5 DRAFT INTERIM DIRECTIVE ID 84-

To: All Operators, All Drilling Contractors,
and the General Public

BLOWOUT PREVENTION AT SOUR WELLS

Reference is made to the recently completed inquiry respecting the 1982 blowout at the AMOCO DOME BRAZEAU RIVER 13-12-48-12 well. The second phase of that inquiry was not related to the specific blowout but dealt with the broad subject of the prevention of blowouts in the Province as a whole.

There was considerable agreement among most participants on a number of the matters dealt with. One such matter related to the need for special safeguards against blowouts in the drilling of certain "critical sour wells". Discussion also took place respecting plans that would minimize impacts on the public should such a blowout occur.

The Board believes this matter to be of considerable importance and urgency and consequently is issuing this draft Interim Directive to define certain wells it considers to be "critical" and to establish requirements for the drilling of those wells. It recognizes that the special requirements will result in somewhat higher drilling costs for these wells but is convinced that these additional costs are warranted particularly having in mind that the potential cost of a blowout at one of these wells is very large. It should also be noted that the special requirements and related costs would apply only to a small portion of the total number of wells drilled in the Province. In 1983, fewer than 50 of the wells drilled would have been designated as "critical sour wells".

The Board intends that these interim requirements will apply for an approximate 6-month period, during which time the adequacy of them will be tested. Comments with respect to these requirements are invited prior to the end of October 1984, from industry, the public, and any other interested parties. The Board would expect to issue a new directive and, as necessary, amend the regulations at the end of the trial period, thus establishing a long-term policy respecting critical sour wells. At that time the Board will review and update, and combine where appropriate, its directives with respect to sour gas. (Interim Directive ID-OG-76-2, Emergency Procedure Plans For Sour Gas Facilities. Interim Directive ID 81-3, Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments.)

This draft Interim Directive is being included in the Phase 2 inquiry report. A task force or committee is being established to review certain of the matters discussed at Phase 2 of the inquiry. The Board believes that the committee should review the appropriateness of this draft directive and the policy it establishes, and should provide its comments by the end of October. If in the meantime and as a result of applying the requirements on an interim basis, particular problems or questions arise, the Board will refer such questions to the committee for its comments.

This interim policy does not change the minimum distance requirements separating sour gas facilities from residential and other developments as set out in Interim Directive ID 81-3. The policy respecting critical sour wells is as follows:

Definition

For blowout prevention purposes a critical sour well is defined as follows:

(a) any proposed well from which the maximum potential hydrogen sulphide (H_2S) release rate is greater than 2.0 cubic metres per second (m^3/sec),

(b) any proposed well from which the maximum potential H_2S release rate is greater than 0.3 m^3/sec and less than 2.0 m^3/sec if the well is to be located within 5 kilometres (3.1 miles) of an urban centre*, or

(c) any proposed well from which the maximum potential release rate is greater than 0.01 m^3/sec and less than 0.3 m^3/sec if the well is to be located within 1.5 kilometres (0.93 miles) of an urban centre, or

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* An urban centre is defined as a city, town, village, or other incorporated centre, and for the purpose of this directive includes any similar development the Board may designate as an urban centre.

(d) any other proposed well which the Board classifies as a critical sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area in which the well is to be located, and the expected complexities in the drilling of the well.

Special Requirements

The applicant for a licence for a critical sour well must satisfy the following special requirements:

1 A satisfactory emergency response plan must be filed with the Board prior to the spudding of the well. The plan must meet the minimum content requirements set out in ID-OG-76-2 and must describe the manner in which the public would be notified, have their safety protected, and be evacuated if necessary, in the event of a blowout. The plan must also have been discussed with members of the rural public and urban representatives that reside within the maximum 100 parts per million isopleth which could be associated with the well. It should also deal with the manner in which the decision would be made as to whether the well would be intentionally ignited in case of a blowout.

This requirement for an emergency response plan is in addition to those set out in ID-OG-76-2 for gas plants and pipelines. Also, pursuant to section 7.060 of the Oil and Gas Conservation Regulations, the Board may continue to request emergency response plans for certain wells which are not "critical sour wells" under this directive.

2 A general description of the drilling plan and the equipment to be used to drill the well must be submitted to and approved by the Board prior to the spudding of the well. The plan would include geological data as necessary but be general in nature and briefly describe any serious drilling problems which may be expected and the manner in which they would be handled. It should also briefly address critical equipment such as the BOPs (including a discussion as to whether or not shear rams will be installed), the drill string, the degasser, the mud system, and procedures, to ensure that all such equipment is fully operative prior to penetrating the critical zone. The plan should also provide for the taking of a directional survey unless the operator can satisfy the Board that it is not needed.

3 The operator must satisfy the Board prior to spudding that supervision during the drilling of the well will be adequate. This will require on-site supervisors with Level 2 certification and some experience in drilling in sour areas. During critical periods at the well, such as drilling into the sour formation, sufficient supervision must be available so that no individual supervisor is required to work a shift longer than 12 hours.

4 The operator must satsify the Board prior to spudding that the drilling crew and key service personnel on the rig are adequate in number and sufficiently qualified. A minimum 5-man drilling crew will normally be required and at least some of the personnel should have experience in sour areas.

5 The operator must satisfy the Board prior to spudding that adequate safety personnel and safety equipment for workers will be on site at all critical times.

6 Intermediate casing set to an appropriate point above the zone from which sour gas or oil is expected will normally be required. However, the Board may exempt certain wells from this requirement if the applicant can demonstrate with a high degree of certainty that intermediate casing is not warranted.

7 A complete inspection and blowout prevention drill will be required prior to drilling out the surface casing and the intermediate casing and before penetrating the formation expected to contain sour gas. The Board field office must be notified at least 48 hours ahead of time so that staff may participate if judged appropriate.

8 If the well is not abandoned, completion and servicing operations will not be permitted without prior consent from the Board. Consent will be granted only if the Board is satisfied that proper equipment and trained personnel will be used and that adequate precautions to prevent a blowout will be taken.

Additional Information to Support Well Licence Applications

The maximum potential H_2S release rate must be submitted as part of a licence application for any well and should be calculated on the basis of the maximum flow rate and H_2S content which can be expected. It should reflect all information available from wells in the area and a realistic engineering approach which recognizes the expected geological setting and reservoir fluid. A detailed description of the type of information required is set out in Attachment I.

Information respecting the maximum potential release rate along with plans for satisfying the above special requirements should be submitted with a licence application for any well which would be a "critical sour well" in accordance with the definition in this directive. In instances where the Board decides that a critical designation should be attached to a well which does not otherwise qualify in accordance with this directive, the applicant for a licence will be sent a deficiency letter requesting information to satisfy the special requirements.

The additional information provided the Board to determine the maximum potential H_2S release rate or to satisfy the above listed special requirements will, with certain exceptions, be considered as public information. Where geological data or personal information respecting individuals is provided as part of the submission, the Board will, upon request from the applicant, consider it as confidential. Such information should be included in a separate volume to avoid inadvertant release. In situations where a well licence application goes to a public hearing the matter can be decided on the basis of only that information which is public. However, the applicant will be provided with an opportunity to reclassify as public, all or a modified part of the data originally filed as confidential.

Comments regarding this directive from industry, the public, or other interested parties should be addressed to the Manager, Development Department (297-8169).

Applicants requiring further information regarding well licensing should address their inquiries to the Well Licensing Section (297-8159) and regarding emergency response plans to the Environment Protection Department (297-8324).

ISSUED at Calgary, Alberta on 25 April 1984.

Vernon Millard
Chairman

Attachment

ATTACHMENT I (ID 84-)

Where an application is made to the Board for a well licence, the applicant shall include in the application the information required in either A or B, as applicable.

A A statement and supporting evidence to the effect that none of the formations to be encountered during the drilling of the well are expected to contain hydrogen sulphide (H_2S).

or

B 1. For each formation to be penetrated which may contain H_2S:

  (a) the maximum expected concentration of H_2S, and the source of this information,

  (b) the maximum expected flow capability at the surface for the case where the unstimulated formation is open to the wellbore as during drilling, and for the case where the well has been completed and the formation stimulated, and the method and information used to determine these values,

  (c) the calculated potential H_2S release rate expressed in the units of cubic metres per second for each of the two cases referred to in (b) above.

2. The maximum potential uncontrolled release rate of H_2S at the stage in the drilling of the well where the sum of the release rates from each formation open to the wellbore is a maximum.

3. The maximum potential uncontrolled release rate of H_2S during the producing stage for the well.

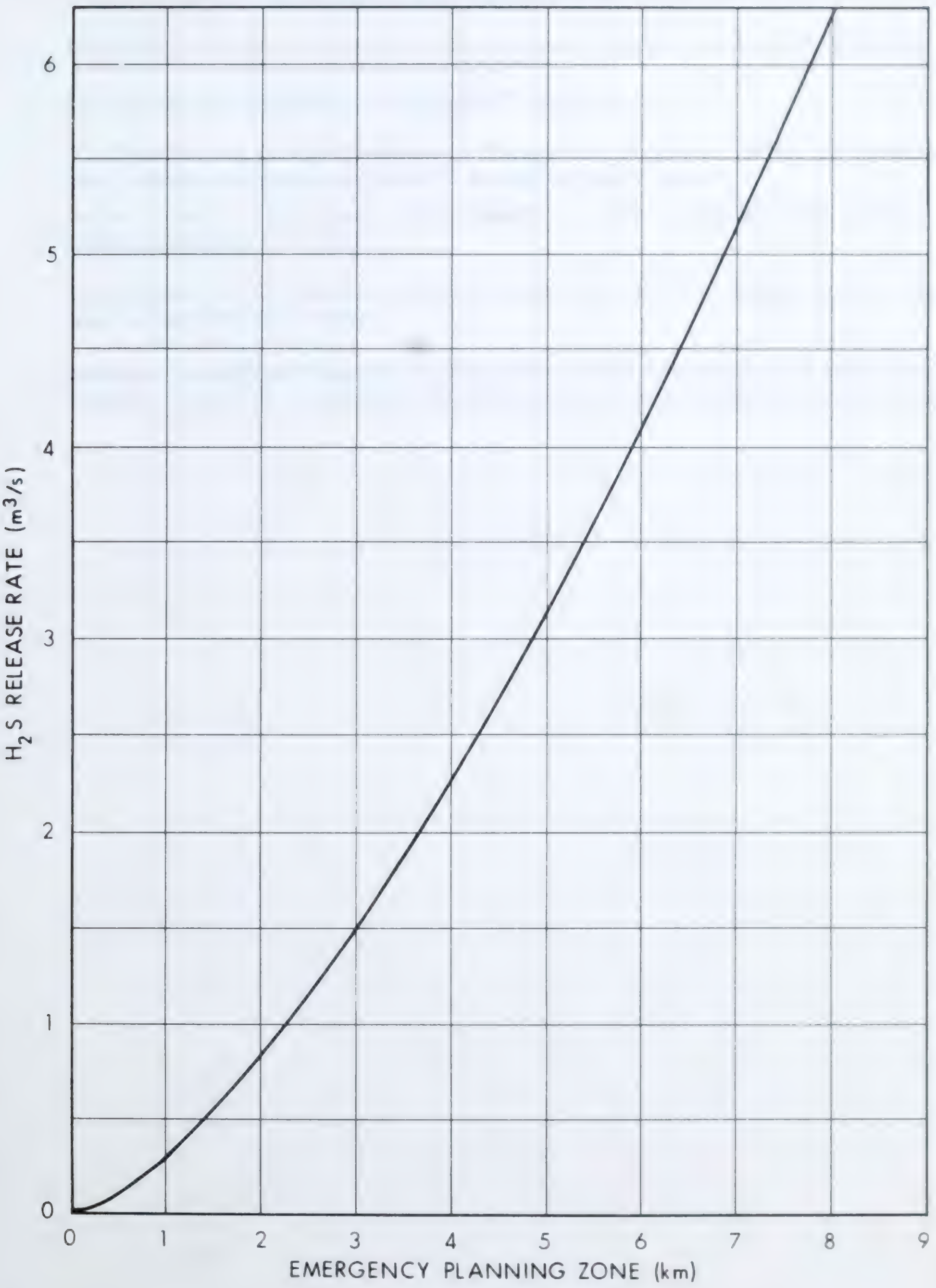
4. The radius of the emergency planning zone for each of 2 and 3 above, determined from the graph in Figure 1 to this Attachment.

5. A map showing the location of all residences and public facilities located within the larger of the emergency planning zones.

6. A statement of the distance to the nearest permanent residence, public facility, rural subdivision, or urban centre beyond the larger of the emergency planning zones, plus an indication of the population density in the general area beyond the planning zone a distance approximately equal to the radius of the planning zone.

It is emphasized that a realistic, responsible engineering approach must be taken. The expected geological setting and reservoir fluids to be encountered must be recognized along with all relevant tests and analyses for the area. In order that the best possible information be available all operators are urged to file the results of tests and analyses with the Board as soon as possible following the completion of the tests.

FIGURE 1 TO ATTACHMENT I
EMERGENCY PLANNING ZONES FOR SOUR GAS WELLS



APPENDIX 6 BLOWOUT PREVENTION REVIEW COMMITTEE TERMS OF REFERENCE

1. Membership will consist of two representatives from each of the ERCB, CAODC, CPA, and IPAC.

2. The Chairman and the Secretary will be the ERCB representatives.

3. The Committee will, through sub-committees if appropriate, investigate, develop recommendations, and report to the parent organizations on each of the subjects listed in Appendix 7.

   Subjects identified as high priority will be reported on or before 1 November 1984. All others will be reported on or before 1 July 1985.

4. The first meeting of the Committee will be held no later than 1 June 1984, and the Committee will remain active as long as the need continues.

5. Government agencies and representatives of the public will be consulted on those matters identified in Appendix 7 and they will be considered for membership on the relevant committees or sub- committees.

APPENDIX 7 BLOWOUT PREVENTION REVIEW COMMITTEE TABLE OF ACTIVITIES AND PRIORITIES

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
1	Critical Sour Well Definition	High	5.1.1
2	Training — Human factors — Driller and crew — Hands-on crew training — 3rd-line supervisors — Surprise drills — Review certification levels — Review certification periods — H_2S awareness — Management awareness — Follow-up — Effectiveness	High	5.1.2
3	Enforcement — Suspension of BOP tickets	Moderate	5.1.3
4	Inspection — More rigorous & frequent function testing of BOPs — Drilling out casings — Entering critical formations — Identify critical depths — Rig deficiency statistics[1]	High	5.1.4
5	Supervision — Special teams for H_2S wells — Two supervisors on critical wells — 2nd-line certificate — 12-hour shifts — BOP drills	High	5.1.5

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[1] The ERCB staff has already started work with the Phase 2 participants to resolve the difficulties with these statistics.

APPENDIX 7 (continued)

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
6	Special Drilling Equipment — Improve kick detection equipment — Monitoring — Degassers — Shear rams[2] — Inside BOPs (floats) — Drill pipe design and metallurgy — H_2S resistant equipment — Location of lower drilling spool — Location of HC valve — Manifold redundancy — Casing pressure gauges — BOP configuration — Master controls location — More automation — Equipment specifications — Drill-string inspection	High	5.1.6
7	Information Exchange — Gather drilling data	Moderate	5.1.7
8	Drilling Plan — Well planning execution — Kick detection/response — Drilling procedures entering critical zone — Tripping and coring procedures — Entering the formation — Lease preparation — Directional surveys — Drill-stem testing — Exchange geological information	Moderate	5.1.9

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[2] PASGEC specifically requested input to these items and the committee must ensure that it is kept informed.

APPENDIX 7 (continued)

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
9	Mud System Design — Underbalanced programs — Conservative mud weights — Mud capacity — pH — H_2S scavengers — Geological conditions — Mud and gas monitoring[2] — Drilling fluids	Moderate	5.1.10
10	Code of Practice for Drilling — Drilling procedures — Tripping and coring — Formation testing — Drill-string design — BOP equipment — Equipment specifications — H_2S-resistant materials	High	5.1.11
11	Winter Drilling Guidelines	Moderate	5.2.2
12	Blowout Equipment Co-operative	Moderate	5.2.5

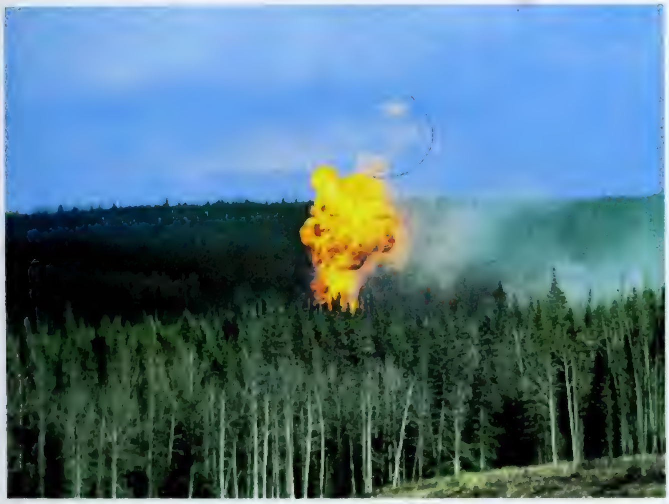
APPENDIX 8 MATTERS TO REFER TO OCCUPATIONAL HEALTH AND SAFETY TABLE OF ACTIVITIES AND PRIORITIES

NO.	ACTIVITY	PRIORITY	REFERRED TO IN REPORT (section no.)
1	Health and Safety — Emergency breathing equipment — Air supply — Training for Supervisors — 12 hour shifts — Safety personnel at critical times — Air monitoring — Respiratory equipment and training	High	5.3.1

APPENDIX 6 PHOTOGRAPHS OF THE 13-12 BLOWOUT

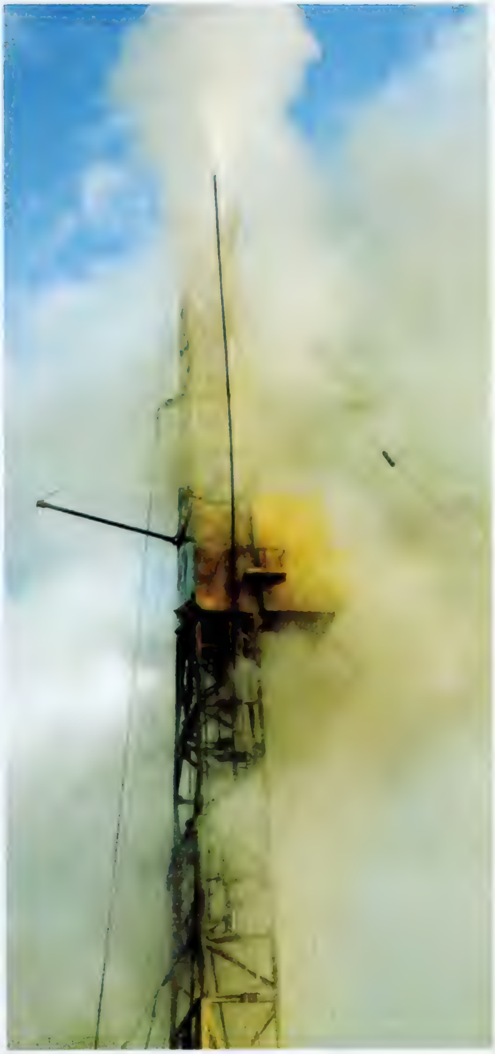
Photographs of the blowout of the 13-12 well showing various scenes, mostly at the site, as the events unfolded.

The 13-12 blowout area prior to the first fire.
Photo credit: W. Wylie, ERCB

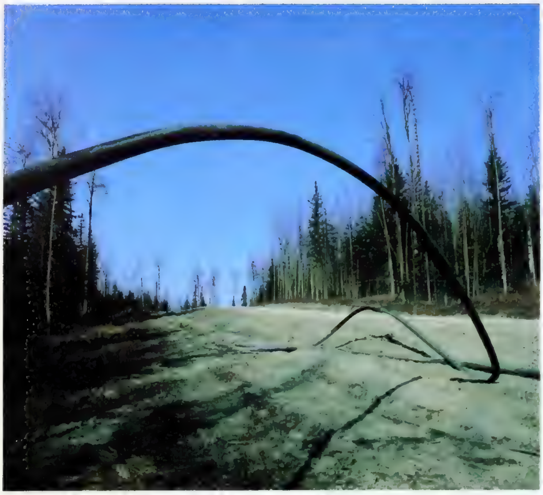


First ignition of the 13-12 well. Note the drill pipe above the flame.
Photo credit: W. Wylie, ERCB

Fire following accidental ignition of 13-12 well.
Photo credit: C Wickstrom, ERCB.

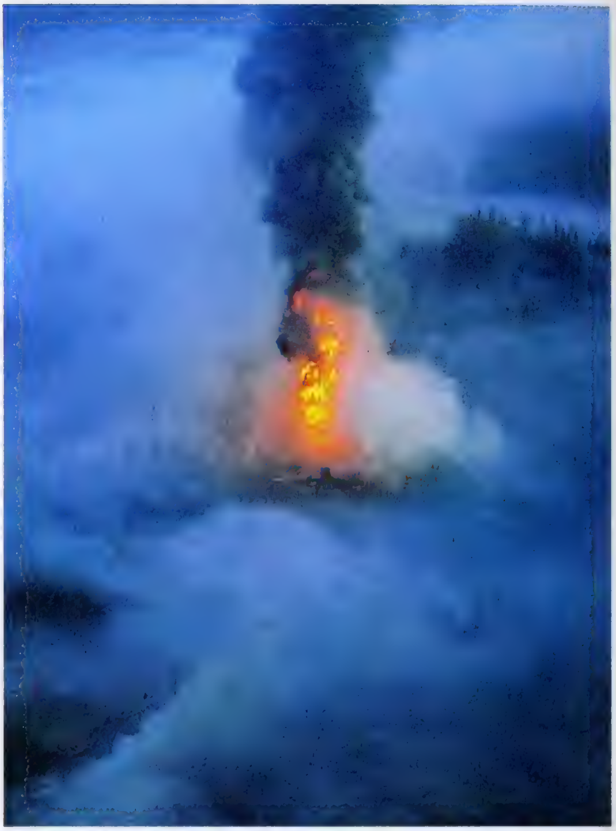


Plan "B" fails. Note the drill pipe
blowing out of the well.
Photo courtesy Standard Safety & Consulting Services (1978) Ltd.

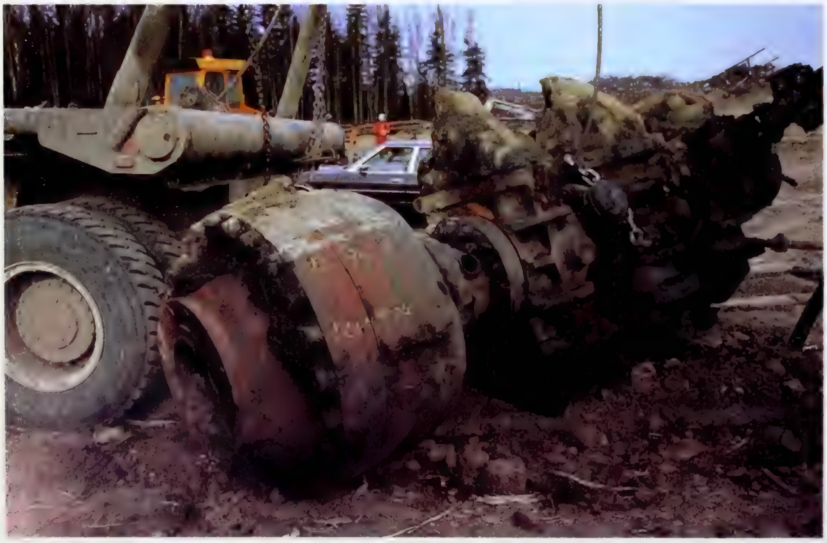


Some of the drill pipe blown out of the well.
Photo credit: W. Wylie, ERCB

On-site rescue ambulance and workers.
Photo credit: W. Wylie, ERCB



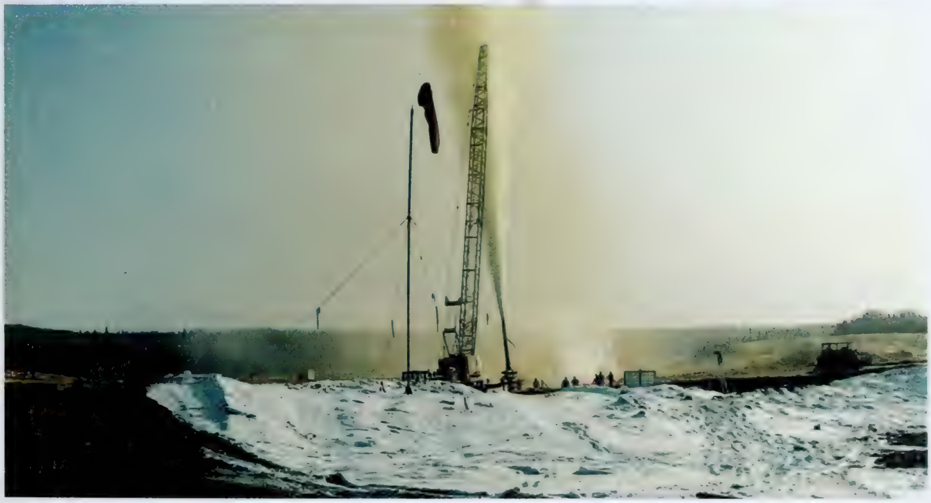
The burned-out area after the first fire.
Photo credit: W. Wylie, ERCB



The blowout preventer stack recovered after the first fire.
Photo credit: W. Wylie, ERCB

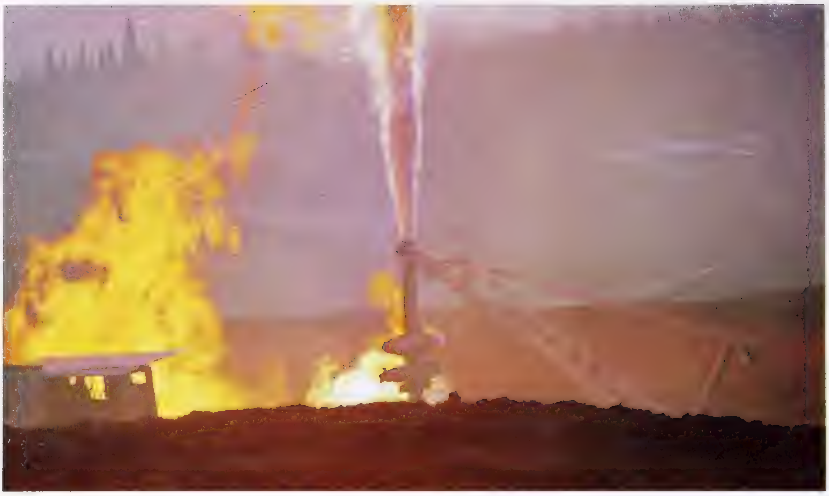
One of the attempts to extinguish the fire.
Photo credit: W. Wylie, ERCB

Mobile air monitoring vehicle.
Photo courtesy Alberta Environment

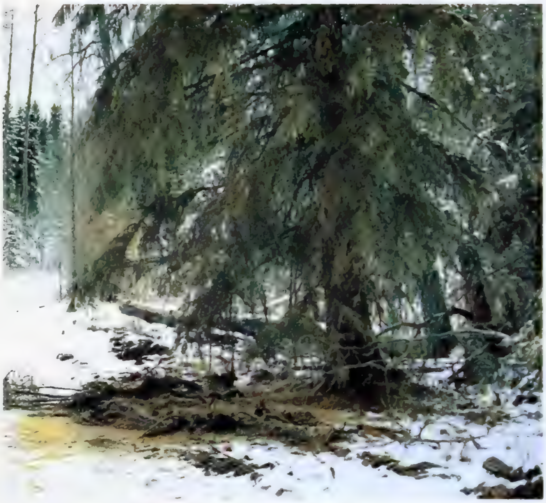


With the fire out, workers attempt to cap the well (Plan "C").
Photo courtesy Standard Safety & Consulting Services (1978) Ltd.

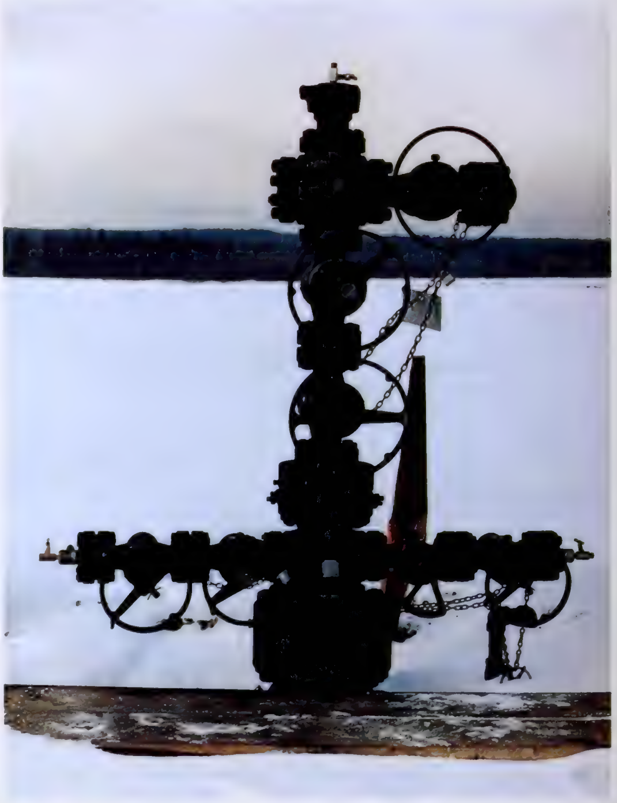
Well-site worker suited and masked-up.
Photo courtesy Standard Safety & Consulting Services (1978) Ltd.



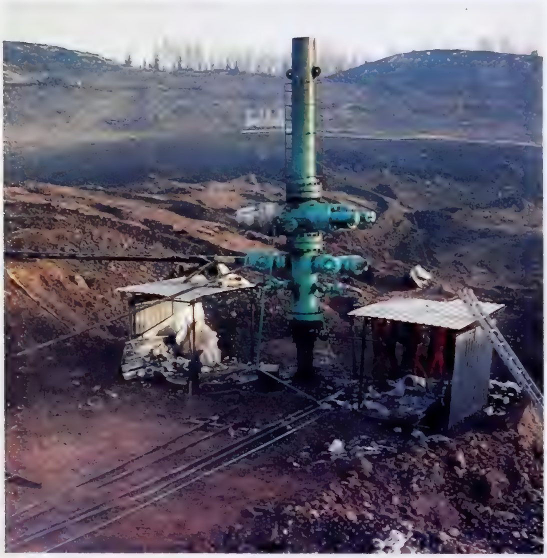
Final capping of the 13-12 well begins.
Photo credit: W. Wylie, ERCB



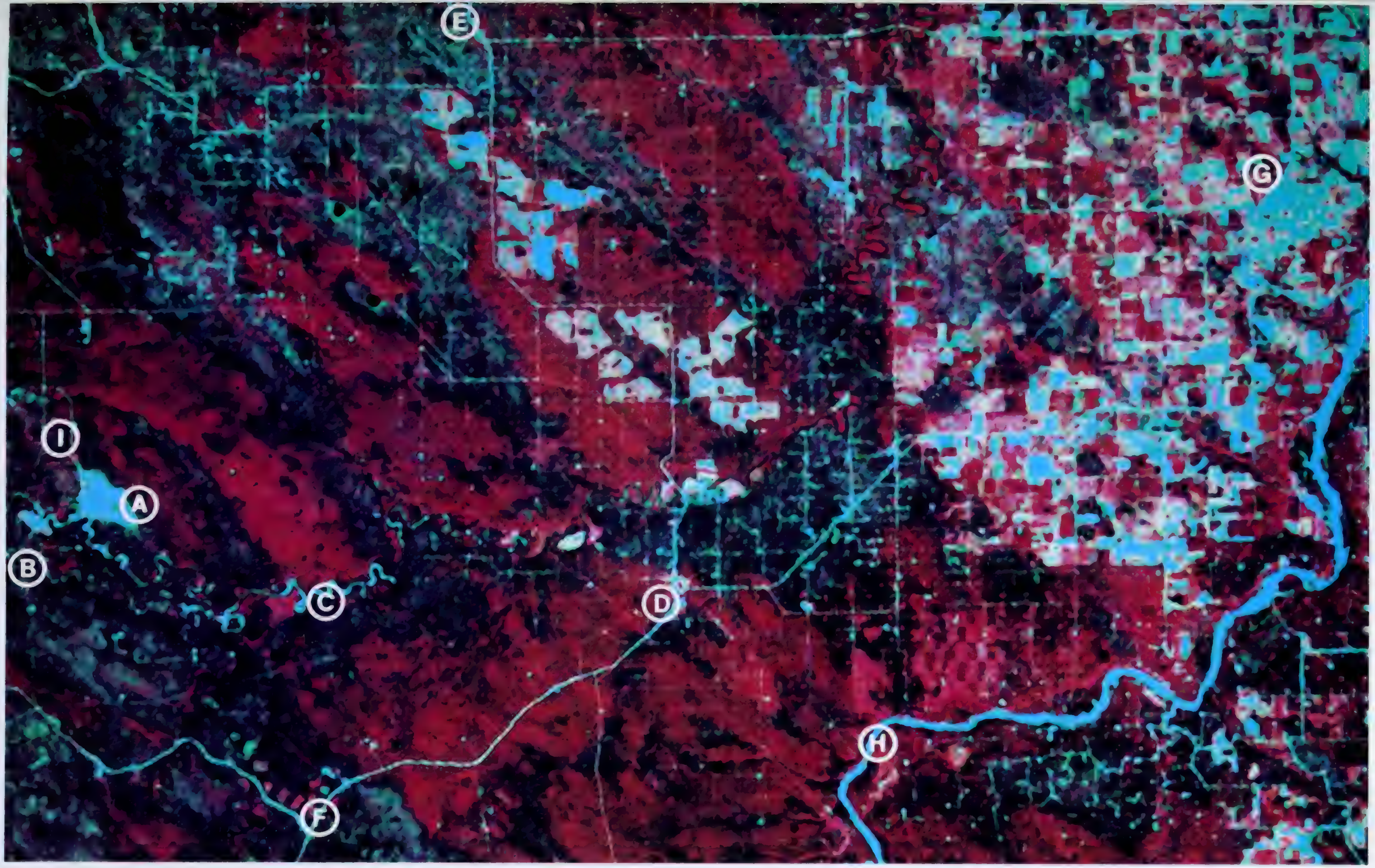
Condensate laden tree near Zeta Creek.
Photo credit: W. Wylie, ERCB



The 13-12 wellhead after completion of the well.
Photo credit: D. Peet, ERCB



The battle with 13-12 is over!
Photo credit: R. Paulson, ERCB



This satellite photo, of a 30 by 20 mile area surrounding the Lodgepole Blowout, was taken in August of 1983.

PLACES OF INTEREST

A	Blowout site, 13-12 well (1982)
B	Blowout site, 7-10 well (1977)
C	Pembina River
D	Lodgepole
E	Cynthia
F	Centennial Lumber
G	Drayton Valley
H	North Saskatchewan River
I	Zeta Creek

COLOURS IN PHOTO

*Brilliant blues (heavily sedimented rivers).

*Pale blue (bare or fallow fields, including two blowout sites).

*Deep red (poplar forest).

*Magenta to brown (muskeg, with trees).

*Black (clear lakes with muck bottoms).

APPENDIX 7 METHOD OF PRESENTING H_2S AIR MONITORING DATA AS USED BY ALBERTA ENVIRONMENT AND AMOCO WHEN OFF-SCALE READINGS WERE ENCOUNTERED BY MOBILE MONITORING INSTRUMENTS

The instruments used in H_2S mobile air monitoring for the blowout incident, some of which had continuous recording capability, had limits which were exceeded by concentrations of H_2S encountered by the instruments. AE, and Amoco's consultant, Monitrex Engineering Ltd., reported the readings for these occurrences in the following manner:

AE

The AE mobile unit monitoring in high H_2S concentration areas had a maximum capability of 30 ppm and did not have a continuous recording device. AE reported a low concentration and high concentration for each monitoring period reported using this machine. The recordings are from a visual observation of a needle scale on the instrument.

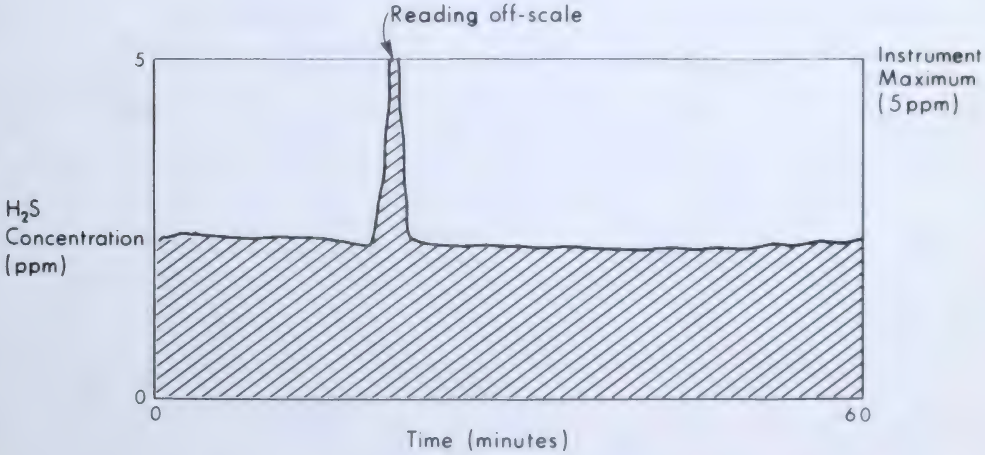
If the instrument went off scale, AE reported this occurrence with the greater-than sign (>) preceding the instrument's maximum (ie, > 30 ppm).

Monitrex

The two mobile monitors used by Monitrex had a recording capability of 5 and 10 ppm, respectively, and each had continuous recording strip chart equipment.

Monitrex presented its mobile and stationary monitoring data in hourly averages using two methods for periods when off-scale readings were obtained:

(a) if the peak off-scale reading lasted for 1 minute or less, the reading would be shown as the average value of the area under the curve. For example:

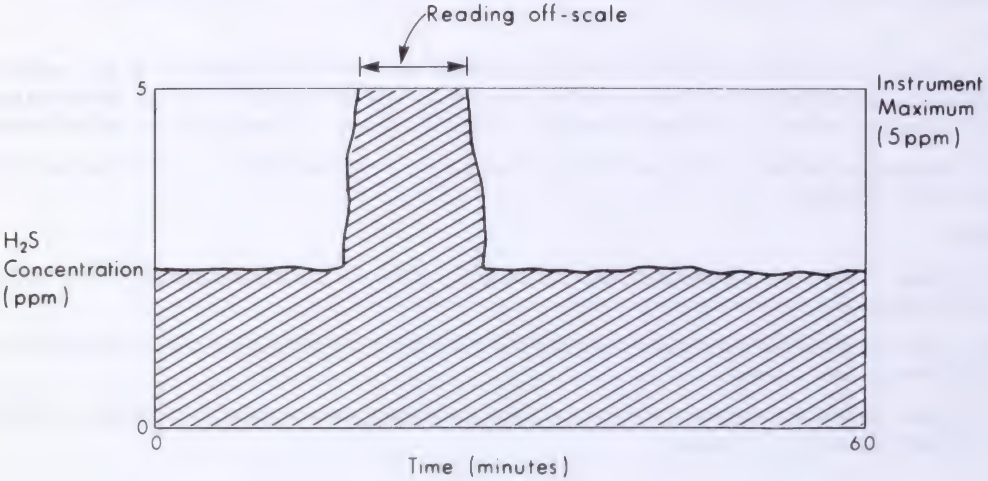


if the area under the curve above (shaded) averages 2.5 ppm, the reading would be presented as an hourly average of 2.5 ppm,

and,

APPENDIX 7 (continued)

(b) if the peak off-scale reading lasted for longer than 1 minute, the reading would be shown as an hourly average of greater than the maximum capability of the machine. For example:



if the off-scale portion as shown above lasted longer than 1 minute, the reading would be shown as greater than 5 ppm, ie, > 5 ppm.

APPENDIX 8 GOVERNMENT OF ALBERTA — PEACETIME EMERGENCY OPERATIONS PLAN FOR A SOUR GAS RELEASE

Government of Alberta

Peacetime Emergency Operations Plan
For a Sour Gas Release

13 April 1984

GOVERNMENT OF ALBERTA

PEACETIME EMERGENCY OPERATIONS PLAN
FOR A SOUR GAS RELEASE

April 13 1984
(Date)

I.D. MARK EGENER
MANAGING DIRECTOR
ALBERTA DISASTER SERVICES

MARVIN E. MOORE
MINISTER-IN-CHARGE
ALBERTA DISASTER SERVICES

GOVERNMENT OF ALBERTA

PEACETIME EMERGENCY OPERATIONS PLAN

FOR A SOUR GAS RELEASE

PURPOSE

1. This plan sets forth the manner in which the Alberta Government departments and agencies will respond to a sour gas release which may affect people and property in Alberta.

AUTHORITY

2. This plan is issued by the Minister responsible for Alberta Disaster Services under the authority of the Disaster Services Act and authorizes the government to respond in a prompt and co-ordinated manner to any release of sour gas.

DEFINITIONS

3. In this plan:

   a. a **sour gas release** is an uncontrolled release of natural gas containing hydrogen sulphide which is so declared to be a Sour Gas Release by the Energy Resources Conservation Board (ERCB).

   b. the **FH Order area** is that area within the boundaries delineated in an FH Order issued by ERCB under Section 89 of the Oil and Gas Conservation Act.

   c. **Minister** means the Minister charged with the administration of The Disaster Services Act.

   d. an **On-site Command Post** is an operations centre set up in the vicinity of the gas release to manage the emergency within the FH Order Area.

   e. a **Main Control Headquarters** is an operations centre set up at a suitable location in support of the On-Site Command Post to manage the larger aspects of the emergency including public relations and the provision of information and advice to affected municipalities.

   f. **Police** is a peace officer as defined in Section 25(1) (0.1) of the Interpretation Act, Chapter I-7 R.S.A. 1980, as being a member of the Royal Canadian Mounted Police or a member of a municipal police force having jurisdiction in Alberta by virtue of Section 18 (1) and Section 19 of the Police Act, Chapter P-12 R.S.A. 1980.

   g. **Local Authority** means:

      (1) the council of a city, town, village, county or municipal district

(2) the board of administrators of a new town; and

(3) in the case of an improvement district or special area, the Minister of Municipal Affairs.

h. **Municipal Emergency Plans** means those emergency plans prepared by a Local Authority pursuant to Section 8(e) of the Disaster Services Act or by or in respect of a Metis Settlement.

i. **Company Emergency Plans** means emergency procedures plans prepared by an industrial operator pursuant to regulation 7.060 (9) (gas wells) or 9.060 (gas plants) made under the Oil and Gas Conservation Act, Regulation 65 made under the Pipeline Act (pipelines) or any other regulation, statute or condition.

GENERAL

4. Sour gas may contain contaminents in concentrations that could be potentially dangerous to the health and safety of people should they become exposed during a release. This plan outlines a method of responding to such an emergency when a sour gas release is declared by ERCB and should be viewed as a plan of general application. This plan describes the concept of operations, responsibilities of Alberta government departments and agencies, and some detailed aspects of the management of the emergency. In the event of any conflict between this plan and existing Acts or Regulations, those Acts or Regulations will take precedence.

IMPLEMENTATION

5. This plan will be implemented in part or in whole on the direction of ERCB.

6. Concept. The response should proceed as follows:

a. ERCB will be made aware of the threat of or the occurrance of an actual sour gas release, by the industrial operator (the licencee) or by other means;

b. ERCB will direct that this plan be activated, in part or in whole, will commence the alerting procedures and will prepare and issue, if appropriate, an FH Order;

c. in accordance with Company Emergency Plans or on the direction of ERCB, the well may be fired;

d. ERCB will establish two headquarters (see Annex A) to manage the response if required:

(1) an On-Site Command Post to deal with matters within the immediate area of the gas release. When a FH Order is made, the immediate area of the release will be the FH Order area; and

(2) a Main Control Headquarters to deal with matters outside the immediate area of the release to provide support to the On-Site Command Post and to provide an interface with the public, the local authorities and the Government of Alberta.

e. ERCB will direct the activities at the On-Site Command Post and the industrial operator's activities related to the sour gas release. Workers' Health, Safety and Compensation has the responsibility for ensuring that all safety measures are observed at the work site,

f. ERCB will direct the activities at the Main Control Headquarters and will co-ordinate the activities of the departments and other government agencies represented there;

g. the Main Control Headquarters' channels for communication (see chart at Annex B) will be:

(1) to the On-Site Command Post;

(2) to those Local Authorities represented at the Main Control Headquarters;

(3) through Alberta Disaster Services to other Local Authorities;

(4) to those government departments represented at the Main Control Headquarters;

(5) through Alberta Disaster Services to government departments not represented at the Main Control Headquarters; and

(6) through Alberta Disaster Services to the Government of Canada except where direct communications are authorized.

h. the Main Control Headquarters is the main source of official information to the public, including health risk and other warnings; and

i. if the situation escalates requiring such additional government support that, in the opinion of the ERCB, it would be difficult to continue to manage all matters at the Main Control Headquarters, Alberta Disaster Services would be tasked to activate the Government of Alberta Emergency Response Centre, to co-ordinate those activities which are impractical to manage at the Main Control Headquarters. The Emergency Response Centre would then be activated in accordance with the Government of Alberta Peacetime Emergency Operations Plan and Procedures.

7. Alerting. ERCB may learn of a sour gas release from many sources. Any government department or agency receiving information regarding a sour gas release will notify ERCB immediately.

.../4

ERCB will immediately alert:

a. Alberta Disaster Services who will in turn alert:

    (1) all other departments, boards, agencies and crown corporations who will be involved in the Main Control Headquarters;

    (2) all municipalities which are or which may be affected;

    (3) any other orders of government which might be involved; and

    (4) any other organizations which might have a role to play or which could otherwise be affected.

b. the RCM Police and/or such other police forces have jurisdiction in the areas involved;

c. the public threatened or potentially threatened;

d. all local authorities whose geographic area is or might be affected by the release;

e. Alberta Environment;

f. Workers' Health, Safety and Compensation;

g. Energy and Natural Resources.

8. Responsibilities

a. The Government of Alberta, its departments and agencies including the ERCB is responsible for:

    (1) developing and maintaining a plan and procedures for a co-ordinated response to a sour gas release;

    (2) establishing an On-Site Command Post and a Main Control Headquarters to co-ordinate the Government's response;

    (3) directing and controlling operations at the location of the sour gas release including, where an FH Order has been made, control of access and egress within the FH Order area;

    (4) providing prompt, co-ordinated assistance and advice to municipalities and the industrial operator engaged in a response to the sour gas release;

    (5) providing information and advice to the public concerning the sour gas release and advice to the people who are or could be affected;

.../5

(6) co-ordinating dealings with and co-operating with the Government of Canada as required;

(7) in the case of an escalation of the emergency, providing additional co-ordinated assistance to the On-Site Command Post and Main Control Headquarters by activating the Government of Alberta Emergency Response Centre.

Detailed On-Site Command Post and Main Control Headquarters functions are at Annex C and departmental and ERCB responsibilities are at Annex D to this plan.

b. Incorporated Municipalities are responsible for implementing their Municipal Emergency Plans to protect the health, safety and welfare of residents, using any or all of the resources available to the municipality;

c. Improvement Districts, Special Areas and Metis Settlements- the Minister of Municipal Affairs is responsible for implementing Municipal Emergency Plans to protect the health, safety and welfare of Improvement District, Special Area and Metis Settlement residents; and

d. Industrial operators will be responsible for implementing their Company Emergency Plans until otherwise directed by ERCB.

NOTE: To avoid jurisdictional confusion, note that the Local Authorities would continue to exercise their normal responsibilities outside of the FH Order area.

9. Monitoring. ERCB will ensure that sufficient monitoring information is gathered so that the ERCB is able to meet their responsibilities under this plan. Obtaining information on contamination levels of hydrogen sulphide and other contaminants is the responsibility of:

a. Workers' Health, Safety and Compensation wherever there are workers that may be affected; and

b. Alberta Environment for all other areas.

10. Public Advisory. Whenever monitoring information indicates that a threat or potential threat exists to members of the public the ERCB or the Main Control Headquarters once it is established, will notify:

a. the public threatened or potentially threatened; and

b. all Local Authorities whose geographical area is or might be affected by the release.

Notwithstanding the aforesaid, if the industrial operator or Alberta Environment, through their monitoring or otherwise, become aware of concentrations of contaminants that present an immediate threat to persons in the area, the industrial operator or Alberta Environment as the case may be, will immediately notify those persons and the On-Site Command Post or the Main Control Headquarters of such a threat.

.../6

11. Evacuation. Evacuation may take many forms and could range from a few individuals to entire small communities exposed to sudden or accumulated concentrations of sour gas. Such action will be recommended to the municipality by the Main Control Headquarters. Evacuation advice will be in one of four general categories. These are:

a. Voluntary. Where the authorities do not consider the hazard sufficient to warrant advising evacuation, some individuals may choose to leave of their own accord.

b. Advisory. Where there may be a hazard to people with respiratory or other health problems, they would be advised to leave;

c. Urgent. Where there is a serious hazard and people's health and welfare could be adversely affected if they didn't leave immediately, this information would be passed by the most expeditious means available which could be by telephone, by loud hailer or by going door-to door; and

d. Enforced. ERCB has the authority to order evacuation out of an FH Order area. A municipality may acquire authority to order evacuation of any part or all of its area of jurisdiction by declaring a State of Local Emergency under The Disaster Services Act.

12. Reception. Alberta Disaster Services will alert those municipalities designated for reception of evacuees and will co-ordinate reception arrangements, where necessary.

13. Security.

a. The RCM Police will be responsible for the control and the security of any evacuated areas in the absence of a recognized municipal police force; and

b. the ERCB will arrange for control of air traffic through the area through the Federal Ministry of Transport who will in turn issue a NOTAM (Notice to Airmen) or a special Federal Ministerial Order.

14. Situation Reports. All Government of Alberta departments, boards and agencies involved in the emergency response will provide the Main Control Headquarters and On-Site Command Post with a situation summary daily, or as otherwise required, which will be amalgamated into a Government situation report.

15. Public Information. The Public Affairs representative at the Main Control Headquarters will manage and release information to the media on behalf of the Main Control Headquarters. The Public Affairs Bureau will establish and staff a public inquiry centre for the Main Control Headquarters for briefing media and responding to inquiries from the general public.

.../7

16. Communications. The telephone will be the primary means of communications. Where practical the telephone will be supported by a "hard copy" capability either as an attachment to the telephone, telex or other means. Should additional communications arrangements be required, Alberta Government Telephones will be tasked to provide them. Alberta Government emergency communications requirements will be co-ordinated through Alberta Disaster Services.

17. Government of Canada Assistance. Requests for federal government assistance from any government department or agency, except where direct communications are authorized, shall be directed to Headquarters, Alberta Disaster Services, for transmission to the Regional Director, Emergency Planning Canada or to the Department of National Defence as necessary.

ANNEXES

Annex A - Sour Gas Release Emergency Response Organization

Annex B - Sour Gas Release Emergency Response Information Flow

Annex C - Sour Gas Release Functions

Annex D - Government of Alberta Responsibilities For Special Services Related To A Sour Gas Release

Annex E - Levels of Hydrogen Sulphide, Their Effects and Counteracting Measures

Annex F - Industrial Operator Responsibilities

Annex G - Glossary of Terms

DISTRIBUTION

ACTION

Minister-in-charge, Alberta Disaster Services

- Executive Assistant

Alberta Disaster Services

- Managing Director
- Assistant Executive Director (DP)
- Assistant Executive Director (DG)
- Division Directors
- District Officers
- Staff Officers
- Emergency Response Centre
- Spares

Government Departments

- Emergency Planning Officers and Alternate Emergency Planning Officers

INFORMATION

Alberta Municipalities

- Directors of Disaster Services, Incorporated Muncipalities

Alberta Legislative Library

- Provincial Archives of Alberta

Government of Canada

- Regional Director, Alberta, Yukon and Northwest Territories, Emergency Planning Canada
- Federal Study Centre, Arnprior, Ontario
- Regional Director, Indian and Northern Affairs
- Director, Western Region, Parks Canada
- Superintendents, National Parks in Alberta
- K Division RCMP
- Commander, Air Command Detachment Edmonton

Provincial/Territorial Emergency Preparedness Organizations

- Canadian Petroleum Association
- Independent Petroleum Association
- Edmonton Pipeline and Utility Operators
- Alberta One - Call

Government of Alberta
Peacetime Emergency
Operations Plan for a
Sour Gas Release

SOUR GAS RELEASE

EMERGENCY RESPONSE ORGANIZATION

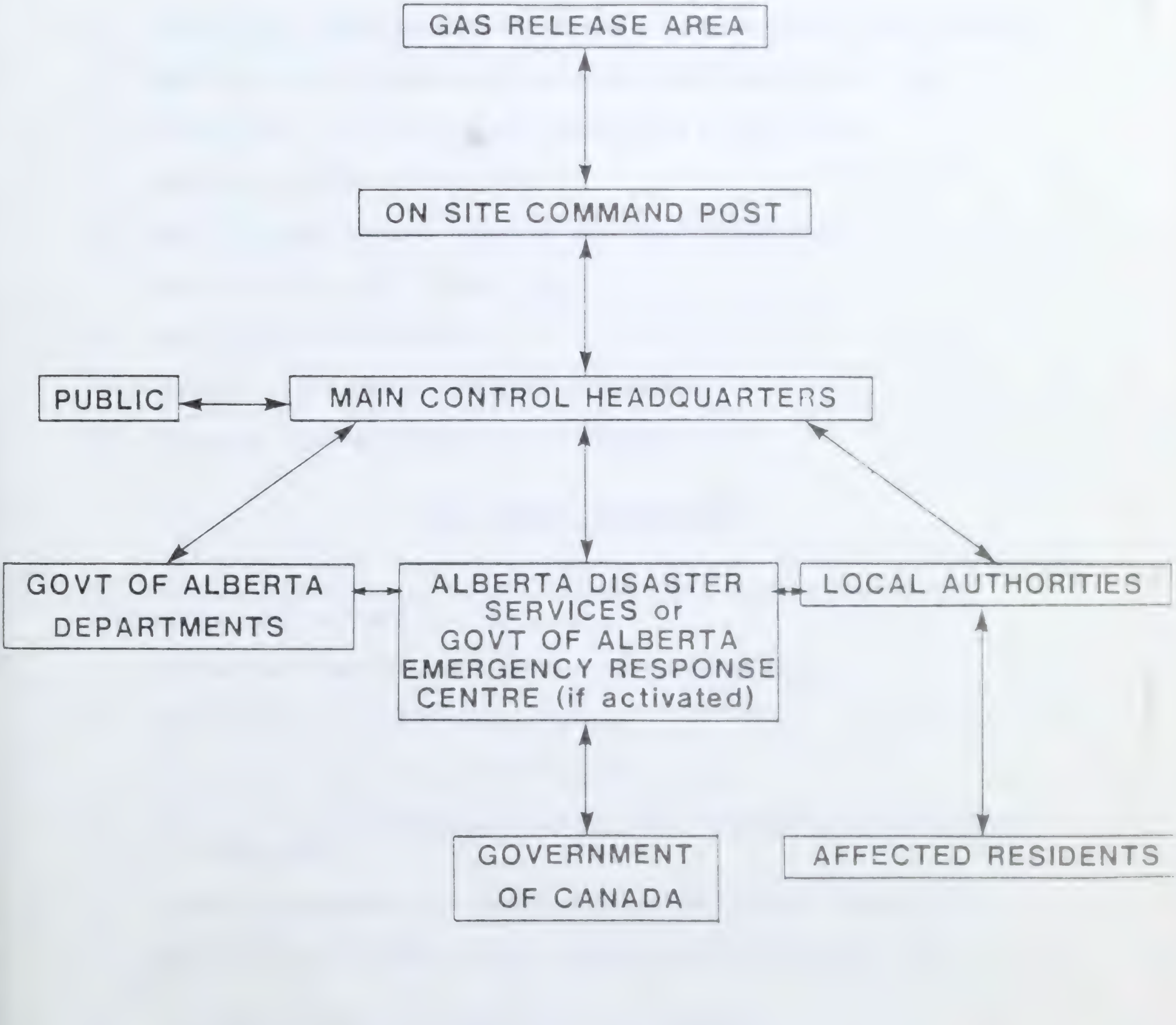
ON SITE COMMAND POST

ERCB
- INDUSTRIAL OPERATOR
- WORKERS' HEALTH, SAFETY and COMPENSATION
- ENVIRONMENT
- ENERGY and NATURAL RESOURCES
- POLICE

MAIN CONTROL HEADQUARTERS

ERCB
- AGRICULTURE
- ENVIRONMENT
- ALBERTA DISASTER SERVICES
- ENERGY and NATURAL RESOURCES
- LOCAL AUTHORITY
- PUBLIC AFFAIRS BUREAU
- POLICE
- SOCIAL SERVICES and COMMUNITY HEALTH and BOARD OF HEALTH
- WORKERS' HEALTH, SAFETY and COMPENSATION
- PLUS OTHER GOVERNMENT DEPARTMENTS AND ORGANIZATIONS AS REQUIRED

SOUR GAS RELEASE EMERGENCY INFORMATION FLOW


GAS RELEASE AREA
ON SITE COMMAND POST
PUBLIC
MAIN CONTROL HEADQUARTERS
GOVT OF ALBERTA DEPARTMENTS
ALBERTA DISASTER SERVICES or GOVT OF ALBERTA EMERGENCY RESPONSE CENTRE (if activated)
LOCAL AUTHORITIES
GOVERNMENT OF CANADA
AFFECTED RESIDENTS

Annex C to
Government of Alberta
Peacetime Emergency
Operations Plan for a
Sour Gas Release

SOUR GAS RELEASE

FUNCTIONS

ON SITE COMMAND POST

1. Control and supervise activity at the site to normalize the situation.
2. Warning to and evacuation of residents within the FH Order area.
3. Protection of life and property within the FH Order area.
4. Safety at the gas release site.
5. Monitoring gas concentrations within the FH Order area.
6. Security within the FH Order area.
7. Local weather information.
8. Technical gas release - related information.
9. Situation reports to Main Control Headquarters.

MAIN CONTROL HEADQUARTERS

1. Provide support to the On-Site Command Post. Compile monitoring information and evaluate.
2. Monitor gas concentrations outside the FH Order area.
3. Determination of the threatened area.
4. Safety of all workers in the threatened area.
5. Security and movement control within the threatened area except within the FH Order area.
6. Liaison, co-ordination and support to affected Local Authorities.
7. Warning and assistance to Local Authorities for evacuation and reception.
8. Situation reports to the Government of Alberta.
9. Situation reports to the On-Site Command Post.

.../2

10. Information to the media.

11. Information to the public.

12. Health effects information.

13. Agricultural effects information.

14. Other environmental effects information.

15. Answer inquiries from the public.

16. Technical advisory services.

17. Obtain weather information.

EMERGENCY RESPONSE CENTRE (IF ACTIVATED)

1. Provide the co-ordinated Government of Alberta support to the Main Control Headquarters.

2. Arrange for any outside resources required by the Main Control Headquarters.

3. Arrange for resources of the Government of Canada or other outside governments, if required, to support the Main Control Headquarters.

4. Situation reports to the Main Control Headquarters.

5. Assume and exercise control of the total response (government, municipal, industrial) upon the declaration of a State of Emergency by the Lieutenant Governor in Council.

GOVERNMENT OF ALBERTA

RESPONSIBILITIES FOR SPECIAL SERVICES

RELATED TO A SOUR GAS RELEASE

1. The following sets forth the responsibilities of Government of Alberta departments, boards, Bureaux and Crown agencies for providing special services related to peacetime emergency operations due to a sour gas release.

2. AGRICULTURE

a. Provide advice to the Main Control Headquarters regarding the effects of contaminents on agriculture and livestock and plants and soil.

b. Provide advice to the Main Control Headquarters on any mitigation procedures or arrangements to be effected.

c. Provide a representative to the Main Control Headquarters on a 24 hour basis, if requested by ERCB.

3. DISASTER SERVICES

a. Effect the Government of Alberta fan-out to alert all affected departments.

b. Alert all affected municipalities.

c. Confirm that "K" Division, RCM Police has been informed.

d. Provide a staff officer to the Main Control Headquarters on a 24 hour basis, if required.

e. Provide a Disaster Services Liaison Officer to the Main Control Headquarters.

f. Activate the Government of Alberta Emergency Response Centre if required.

g. Collect, collate and analyse the Government of Alberta peacetime emergency operations costs.

h. Co-ordinate reception plans for evacuation and reception municipalities.

i. Inform Alberta Government Telephones of priority of emergency communications.

j. Make recommendations to Government regarding assistance to disaster victims and the sharing of costs of emergency or disaster operations.

k. Co-ordinate the preparation and regular review of the Sour Gas Release contingency plan.

4. ENERGY AND NATURAL RESOURCES

a. Provide emergency temporary accommodation and emergency feeding equipment, if requested by ERCB.

b. Provide assessment relating to all aspects of the renewable resources sector.

c. Provide advice to ERCB with regard to the firing of a sour gas release in the public lands.

d. Provide a representative to the Main Control Headquarters on a 24 hour basis, if required by ERCB.

5. ENERGY RESOURCES CONSERVATION BOARD

a. Alert the Government of Alberta to a sour gas release through Alberta Disaster Services.

b. Declare a sour gas release and inform Alberta Disaster Services, the RCM Police nearest the scene, the public threatened or potentially threatened, all Local Authorities whose geographic area is or might be affected by the release, Alberta Environment, Energy and Natural Resources, Workers' Health, Safety and Compensation and Alberta Disaster Services.

c. Determine the extent of the immediate hazard and issue an FH Order if considered necessary.

d. Direct the firing of a sour gas release if required.

e. Ensure the industrial operator is advising persons in immediate danger of high contaminent concentrations to evacuate by house-to-house contact (assisted by RCM Police and the Local Authority).

f. Supervise and control operations and mitigation activities within the FH Order area including the ordering of enforced evacuation and the control of access.

g. Arrange for the security of the FH Order Area.

h. Establish an On-Site Command Post and a Main Control Headquarters and direct the activities thereof.

j. Arrange for closure of airspace as required.

.../3

6. ENVIRONMENT

a. Manage all sour gas monitoring activities except those activities for which Workers' Health, Safety and Compensation are responsible under the Occupational Health and Safety Act.

b. Determine areas at risk from the sour gas release.

c. Recommend evacuation to Main Control Headquarters of any areas where excessive levels of sour gas, as determined in consultation with Social Services and Community Health, are detected. (In emergency situations nearby residents will also be warned.)

d. When required, establish an appropriate weather facility in the vicinity of the sour gas release.

e. Provide representatives to the On-Site Command Post and the Main Control Headquarters on a 24 hour basis.

7. MUNICIPAL AFFAIRS

a. Provide damage and loss appraisals of property to affected citizens within the expertise of the department.

b. Manage the emergency response, including the declaration of a State of Local Emergency for those municipalities over which the department has direct control.

c. Provide a representative to the Main Control Headquarters on a 24 hour basis, if requested by ERCB.

8. PUBLIC AFFAIRS BUREAU

a. Keep the public informed by:

(1) Making public information releases based on the situation report developed at the Main Control Headquarters;

(2) making information releases regarding the general effects to health, safety and welfare; and

(3) other information activities as considered desirable.

b. Assign a Public Affairs Officer to the Main Control Headquarters on a 24 hour basis and to the Emergency Response Centre, if activated.

c. Establish and staff a public inquiry centre with a publicized centre telephone number to support the Main Control Headquarters.

d. Establish a Public Affairs Management Control Centre at the Public Affairs Bureau responsible for all Public Affairs information coordination.

.../4

9. SOCIAL SERVICES AND COMMUNITY HEALTH/PROVINCIAL BOARD OF HEALTH/LOCAL BOARD OF HEALTH

a. Establish health safety levels for the escaping contaminants. (see Annex E)

b. Monitor the health effects of the incident, to ensure appropriate data is collected and investigate such health effects. Advise on the appropriate remedial measures to be undertaken. May recommend further investigations after the event.

c. Provide health advice to those response organization personnel developing action guidelines for the levels of sour gas which could be involved in the release.

d. Provide health advice and safety levels for any health care or special care facilities and for the more vulnerable residents.

e. Provide advice to the government, particularly the Public Affairs Bureau representative at the Main Control Headquarters. on the existing or potential health effects of the incident.

f. Provide information to the public inquiry centre.

g. Provide a representative to the Main Control Headquarters on a 24 hour basis, if requested by ERCB.

h. Ensure that the necessary expertise, resources and information are available to local health authorities for them to carry out their role.

i. The local health authority ensures that individual members of the public are informed of specific risks and that appropriate health information is provided to Local Authorities and health care facilities.

10. SOLICITOR GENERAL

Through the RCM Police or a recognized police force:

a. Maintain law and order.

b. Warn and reinforce local police services, if required.

c. Notify the Alberta Disaster Services Duty Officer of a sour gas release.

d. Security control as required.

e. Act on behalf of the medical examiner in accordance with the Fatalities Inquiries Act.

f. Traffic and crowd control.

g. Provide a representative to the On-Site Command Post and Main Control Headquarters on a 24 hour basis.

.../5

11. WORKERS' HEALTH, SAFETY AND COMPENSATION

a. Monitor the health and safety of all occupations at a work site, except agriculture, and ensure that necessary precautions are taken to protect the workers' health and safety during the emergency;

b. Ensure that equipment and personnel required for on-site evaluation of chemical levels are provided by the appropriate employers;

c. Provide information on toxic chemicals to the Main Control Headquarters; and

d. Provide a representative to the On-Site Command Post and the Main Control Headquarters on a 24 hour basis.

12. ALBERTA GOVERNMENT TELEPHONES

a. Provide emergency communications services to government departments as co-ordinated by Alberta Disaster Services.

b. Provide operating and maintenance personnel to ensure the continuity of emergency communications services.

Annex E to
Government of Alberta
Peacetime Emergency
Operations Plan for a
Sour Gas Release

LEVELS OF HYDROGEN SULPHIDE

THEIR EFFECTS AND COUNTERACTING MEASURES

1. At levels below 5 parts per million, people may experience effects such as headache, nausea, eye irritation and wakefulness. These are not serious and are reversible. Above 5 parts per million a health hazard may exist. The following action levels have therefore been established as a guide:

   a. When average levels exceed 5 parts per million for 6 hours or 10 parts per million for 1 hour or more and symptoms persist or become more severe, individuals should consider moving from the area.

   b. When average levels exceed 10 parts per million for 8 hours or more, local conditions in the area will be assessed and individuals may be advised to leave the area.

   c. When environmental monitoring indicates that a level of 20 parts per million or more will be reached and conditions indicate that a health hazard exists, urgent evacuation will be advised.

2. Similar information regarding other contaminants will be added. These stated levels are to be used as a guide only. Government health authorities will either confirm or amend these levels at the time of the sour gas release and in the light of information available at the time.

3. These levels of contaminents will be reviewed and may be adjusted after the publication of the Lodgepole Report.

Annex F to
Government of Alberta
Peacetime Emergency
Operations Plan for a
Sour Gas Escape

N.B. Although not a part of the plan, this Annex is included as information.

INDUSTRIAL OPERATOR RESPONSIBILITIES

1. Tell ERCB of the sour gas escape.
2. Fire sour gas if industrial operator procedures so state or if directed by ERCB.
3. Monitor contaminant levels downwind as directed by industrial operator procedures or ERCB.
4. Ensure residents near release site are notified of the hazard and evacuation guidelines.
5. Ensure that arrangements are made for transportation for the prompt evacuation of residents immediately at risk.
6. Notify residents of evacuation advice or order as directed.
7. Provide input to strategy for control of well.
8. Provide monitoring personnel and equipment.
9. Provide support and take such further action as directed by ERCB.

GLOSSARY OF TERMS

ERCB	Energy Resources Conservation Board
FH Order	Fire Hazard Order. Issued by ERCB to close off a specific area to unauthorized personnel.
Order of government	Municipal, provincial, federal
State of Emergency	Declaration by the Lieutenant Governor in Council to acquire additional powers under The Disaster Services Act to deal with an emergency or disaster
State of Local Emergency	A declaration by a Local Authority to acquire similar emergency powers to deal with an emergency or disaster

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LODGEPOLE
Blowout Report

Addendum to Report D84-9

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LODGEPOLE BLOWOUT INQUIRY

ADDENDUM TO THE PHASE 1 REPORT

WITH RESPECT TO THE FLOW RATE OF THE BLOWOUT OF THE WELL, AMOCO DOME BRAZEAU RIVER 13-12-48-12

DECEMBER 1984

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LODGEPOLE BLOWOUT INQUIRY PANEL

LODGEPOLE BLOWOUT INQUIRY PANEL
ADDENDUM TO THE PHASE 1 REPORT

The Addendum concerns

> The flow rate of the well, AMOCO DOME BRAZEAU RIVER 13-12-48-12, which blew out of control on 17 October 1982.

Published December 1984

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640 Fifth Avenue SW
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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ADDENDUM TO THE LODGEPOLE BLOWOUT INQUIRY PHASE 1 REPORT (DECISION D 84-9): NEW INFORMATION RESPECTING THE ESTIMATED FLOW RATE FROM THE 13-12 WELL

1 INTRODUCTION

Evidence at the inquiry indicated that the estimated flow rate for the well, AMOCO DOME BRAZEAU RIVER 13-12-48-12 (13-12 well), was approximately 1.4×10^6 m^3/d. This was the rate estimated to have prevailed during the last 52 days of the blowout after the crimped drill pipe and other restrictions to flow were no longer in place. In section 3.4 of the Lodgepole Blowout Inquiry Phase 1 report (the report), the Panel indicated that a partial flow test of the well had been conducted subsequent to the inquiry, and while details of the test had not been made public, the Panel understood that the 13-12 flow rate could have been substantially higher than estimated during the inquiry. Notwithstanding the possibility of a higher flow rate, the original estimate of 1.4×10^6 m^3/d was adopted by the Panel, and is reflected in the text of the report and in the recommendations, although in some sections of the report reference is made to the implications of a possibly higher flow rate.

2 REASONS FOR THIS ADDENDUM

The ERCB has recently received the results of the partial test conducted at the 13-12 well, during the period 11-16 July 1984. In addition, the results of the test were discussed at an ERCB public hearing on 27 to 29 November 1984, dealing with the appropriate depletion strategy for the Nisku pools in the general area of the blowout.

The July test at the 13-12 well had to be interrupted because of equipment capacity problems, and consequently, the well was only tested at actual flow rates of 540×10^3 m^3/d or less. However, techniques exist for interpreting such test data and estimating the maximum rate at which the well could have flowed had it been produced in a wide open condition. Estimating the flow rate requires considerable interpretation when actual test rates are substantially less than the estimated open-flow potential, as was the case for the 13-12 well test. Nevertheless, a detailed analysis of the data suggests the flow from the well during the blowout was considerably greater than the 1.4×10^6 m^3/d reflected in the report and was likely at least twice as high as the estimate and possibly three times as high or more.[1]

---

[1] The Panel understands that, at the ERCB hearing on 27 to 29 November 1984, Amoco gave evidence that it still believes the flow rate of the 13-12 well is in the order of 1.4×10^6 m^3/d.

The difference between the previously estimated flow rate of 1.4×10^6 m^3/d and current indications of at least 2.8×10^6 m^3/d and possibly 4.2×10^6 m^3/d or greater, is so substantial that the Panel considers it essential to make this new information available. Additionally, the Panel believes it necessary to review its findings and recommendations as presented in the report in light of the higher flow figures.

3 REVIEW OF THE FINDINGS AND RECOMMENDATIONS OF THE REPORT

The Panel has reviewed the findings and recommendations of section 12 of the report in light of the new estimated flow rates. While the Panel does not see the need to alter any of its previous findings or recommendations, the new information does assist in better understanding some of the matters discussed at the inquiry and addressed in the report. Indeed, in many respects, the new information only adds emphasis to several of the Panel's recommendations.

3.1 Cause of the Blowout

The Panel believes the knowledge that the 13-12 well penetrated a much more productive zone than was anticipated helps explain several aspects of the blowout. The volume of gas entering the wellbore while the kick developed to the blowout stage was probably much larger than previously estimated. That information assists in better understanding the difficulties encountered by Amoco as it attempted to circulate out the kick, as well as the failures of the degasser, and the pipe being forced out of the hole. It also reinforces the Panel's conclusion that drilling operations should be carefully planned, making full allowance for unexpected developments. Additionally, it emphasizes the need to conduct drilling operations in an extremely cautious manner, particularly when drilling in the critical zone.

3.2 Regaining Control of the Well

The significantly higher flow rate helps explain the difficulties encountered by the well-control specialists when trying to regain control of the 13-12 well. It is not likely that this knowledge would have altered any of the well-control plans, although it might have increased the degree of planning and caution exercised by the well-control crew.

The higher flow rate helps explain why the drill pipe blew out of the hole during control Plan B, resulting in the first fire. It may have aggravated the accident which interrupted the Plan C capping attempt, because a much greater volume of raw sour gas would be deflected when the capping assembly was being lowered through the well flow to be bolted on to the casing.

3.3 Effects of the Blowout

In its report, the Panel concluded that during the 67 days the well was out of control, there was a daily emission of 150 to 450 tonnes of sulphur and 300 to 1100 m^3 of condensate. The new flow rate estimate results in at least a doubling of those values, and perhaps a tripling. Consequently, for 52 days sulphur emissions from the well were in the order of 900 tonnes per day, and possibly as high as 1400 tonnes per day. By way of comparison, emissions from all of the sour gas plants, power plants, and oil sands plants operating in the province are about 750 tonnes per day. Emissions of condensate were in the order of 2200 to 3300 m^3/d.

Because the Panel evaluated the effects of the blowout on human health by consideration of anecdotal evidence submitted by local residents, a change in the estimated flow rate does not affect the related conclusions. However, the new information does help explain the extent of the reaction by the public to the event. It also makes it understandable why odours occurred over such a broad area of the province, and indeed, on several occasions well beyond the province.

The new information is particularly significant in comparing actual H_2S concentrations recorded by monitors with the estimated concentrations. The former, of course, would reflect the impact of the actual emissions from the well. The latter, at least during the inquiry, and during the subsequent review of the evidence by the Panel, were based on a flow rate of 1.4×10^6 m^3/d. The new higher flow rate would alter the estimated isopleth values shown in Figure 7.5 of the report. A revised figure has been prepared using flow rates of 2.8×10^6 m^3/d and 4.2×10^6 m^3/d, and 25 per cent H_2S gas. Figure A.1 shows that the 15-ppm isopleth band for these two flow rates lies east of Drayton Valley, and as much as 48 to 66 km from the well.

One of the matters discussed in the report was the recommendation by PASGEC, that for emergency planning purposes, the 15-ppm isopleth should be adopted rather than the current 100-ppm isopleth. In considering that recommendation, the Panel concludes, in the report, that the predicted H_2S concentrations under the isopleth system were several times greater than actual monitoring results. The change in the flow rate only emphasizes the very conservative nature of the isopleth calculation. To illustrate this point, the Panel has plotted in Figures A.2 and A.3 the actual hourly H_2S concentrations recorded at the Drayton Valley stationary monitoring unit during the two periods when the well was not on fire, as well as the isopleth value at Drayton Valley. Assuming the 2.8×10^6 m^3/d flow rate, the isopleth value at Drayton Valley would be about 17 ppm. The figures show that the monitor did not record any concentrations for most of the 26 days and that the highest concentration recorded was 2.7 ppm. The Panel has made similar comparisons for the Cynthia and Lodgepole stationary monitors, shown in Figures A.4, A.5, A.6, and A.7. While there are a few instances when concentrations exceeded the recording capacity of the monitor, the data confirms the extreme conservatism inherent in the isopleth values. The Panel believes that the new evidence substantiates the view expressed in the report that the ERCB should reconsider the use of the 100-ppm calculated isopleth as the basis for establishing the planning zone in emergency response plans.

3.4 Responses by ERCB and Government Departments

The Panel believes the new information emphasizes the several recommendations made respecting the ERCB and Government departments. It provides a new dimension respecting the need for effective communication and co-ordination. It reinforces the Panel's views that all of the parties should have been more cognizant of, and responsive to, the emissions from the well.

3.5 Summary

The knowledge that the 13-12 well was likely flowing at two or three times the volume estimated at the time of the inquiry does not change the overall conclusions of the report. It helps explain some of the events that took place during the blowout and generally reinforces many of the Panel's recommendations. The new information identifies the Lodgepole event as being a unique incident, with probably one of the highest H_2S release rates that could be encountered anywhere in the province.

ISSUED at Calgary, Alberta, on 11 December 1984.

LODGEPOLE BLOWOUT INQUIRY PANEL

Millard

V. Millard
Inquiry Panel Chairman

John Markham

J. W. Markham, M.B.
Panel Member

GJ DeSorcy

G. J. DeSorcy, P.Eng.
Panel Member

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N. A. Strom, P.Eng.
Panel Member

FA Herbert.

F. A. Herbert, M.D.
Panel Member

Sherman Weaver

R. S. Weaver, Ph.D.
Panel Member

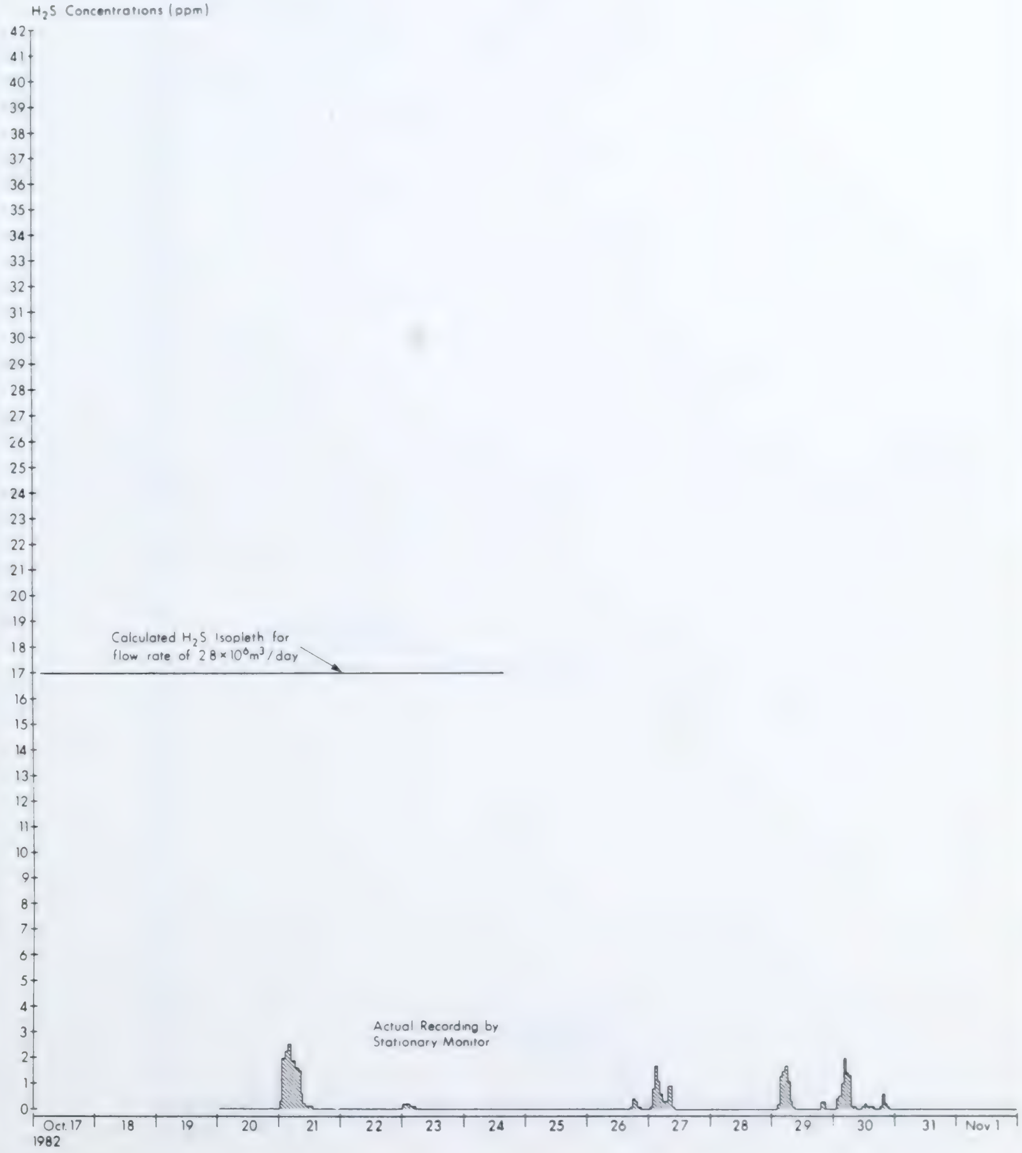

FIGURE A.2 H_2S CONCENTRATIONS RECORDED BY THE DRAYTON VALLEY STATIONARY MONITOR.
17 October to 1 November, 1982.

H_2S concentrations greater than 5ppm recorded at Drayton Valley by mobile monitor are summarized on table 7.1 of the report

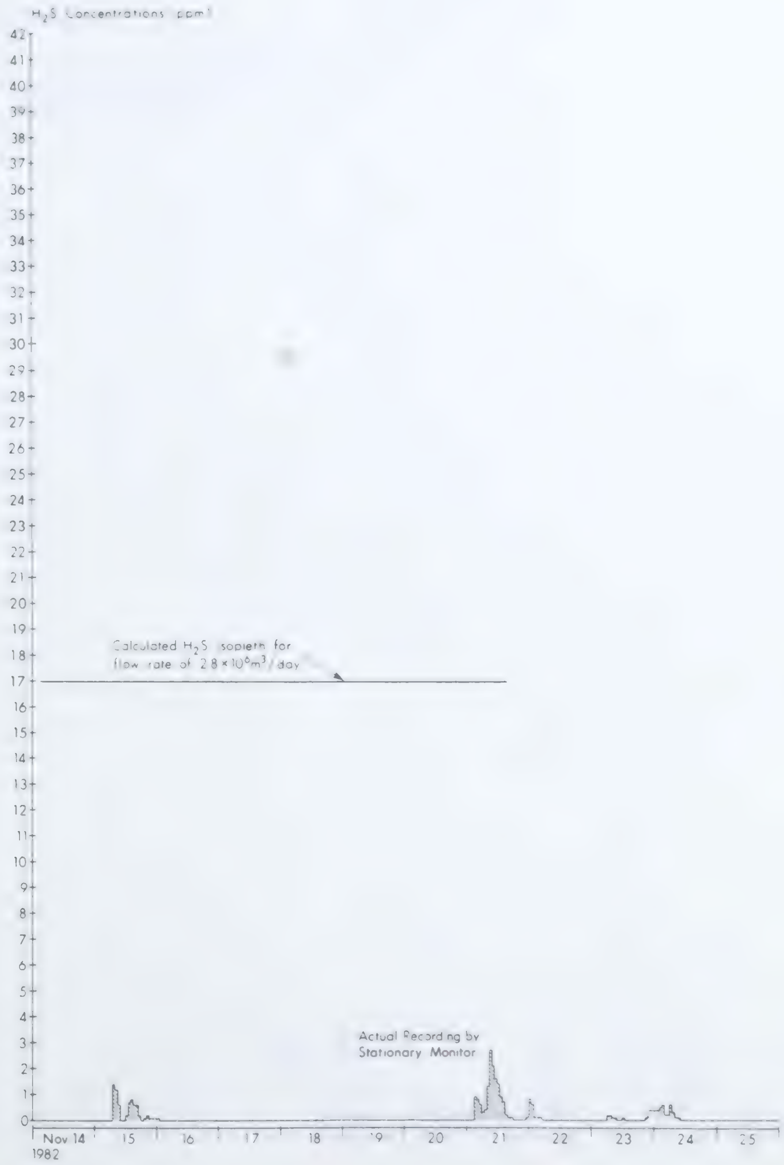

FIGURE A.3 H_2S CONCENTRATIONS RECORDED BY THE DRAYTON VALLEY STATIONARY MONITOR
14 November to 25 November, 1982.

H_2S concentrations greater than 5ppm recorded at Drayton Valley by mobile monitor are summarized on table 7.1 of the report

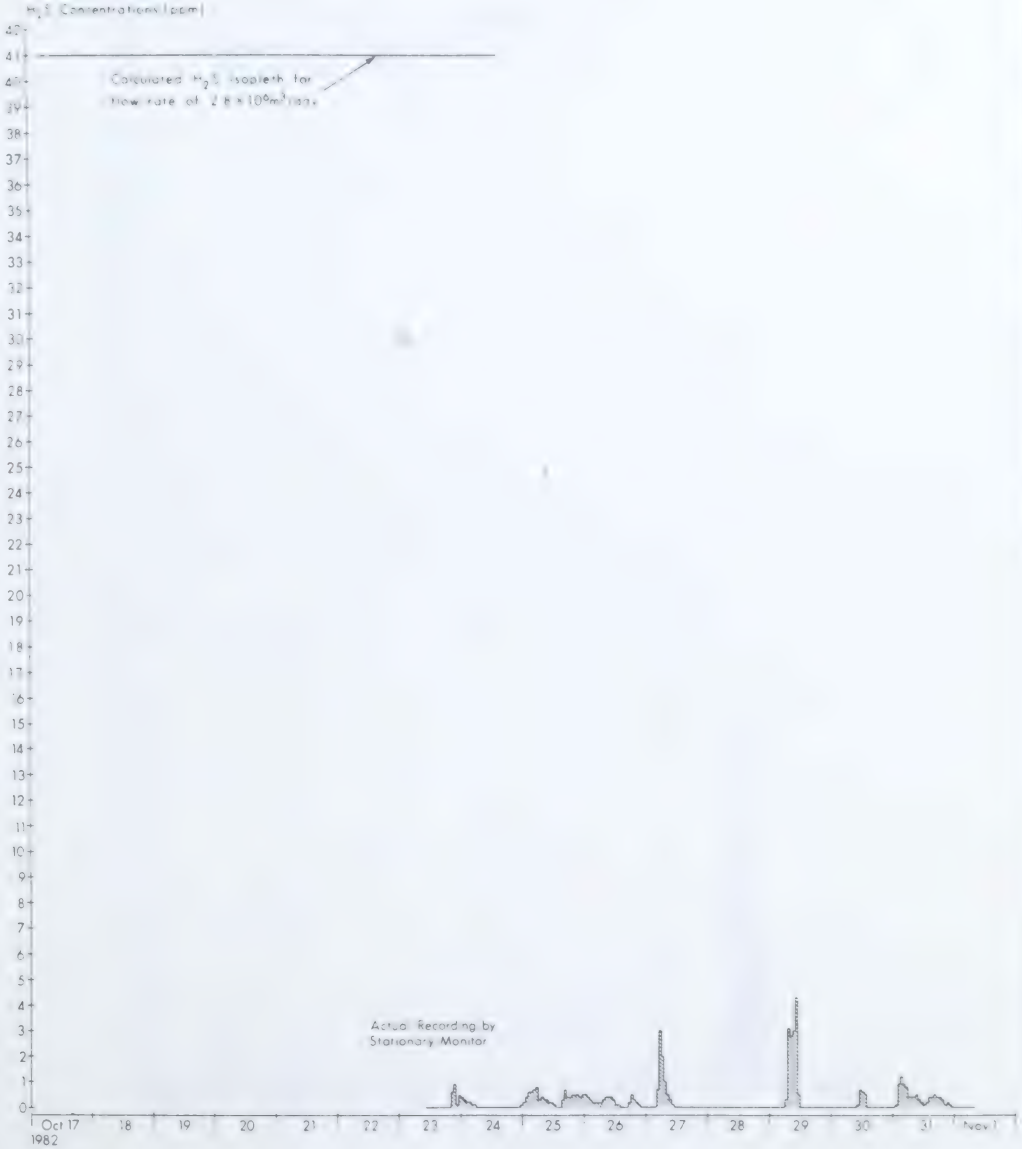

FIGURE A.4 H_2S CONCENTRATIONS RECORDED BY THE CYNTHIA STATIONARY MONITOR
17 October to 1 November, 1982.

H_2S concentrations greater than 5ppm recorded at Cynthia by mobile monitor are summarized on table 7.1 of the report

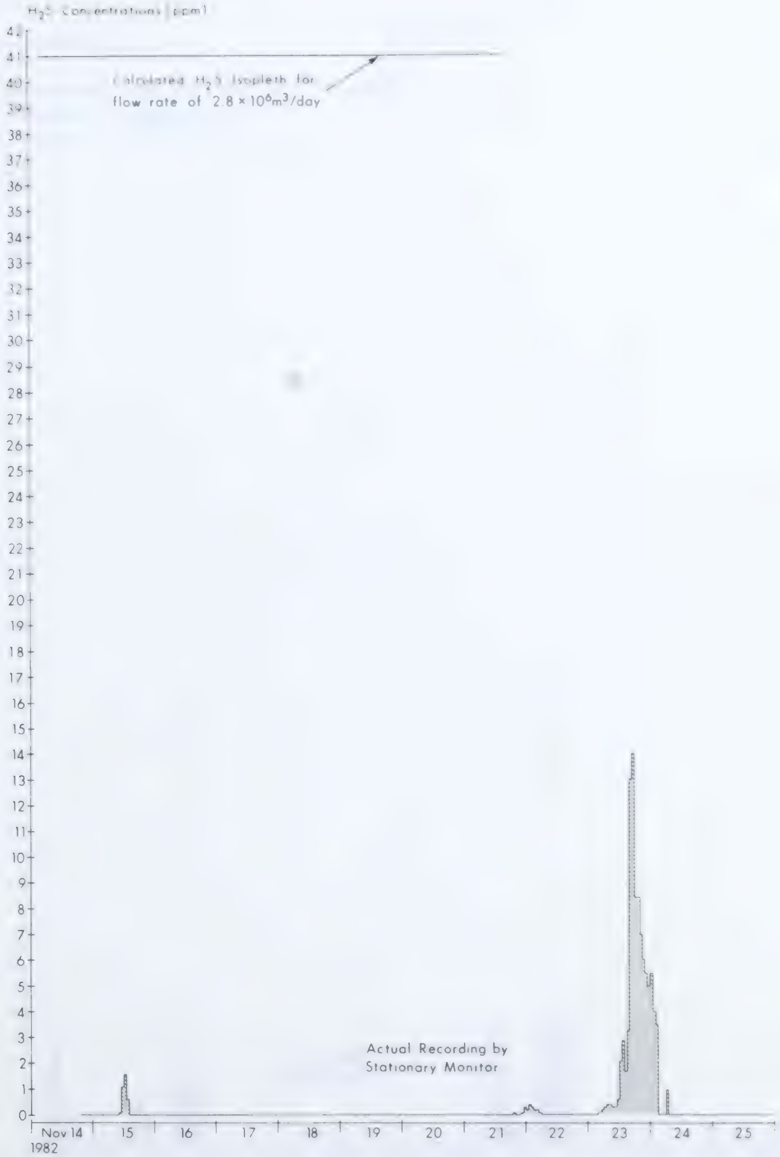

FIGURE A.5 H_2S CONCENTRATIONS RECORDED BY THE CYNTHIA STATIONARY MONITOR.
14 November to 25 November, 1982.

H_2S concentrations greater than 5ppm recorded at Cynthia by mobile monitors are summarized on Table 7.1 of the report.

The stationary monitor at Cynthia did not function from 00:00 to 17:00 24 November

H_2S concentrations shown for the period 16:00 23 November to 07:00 24 November were recorded by mobile monitors and are taken from Figure 7.4 of the report.

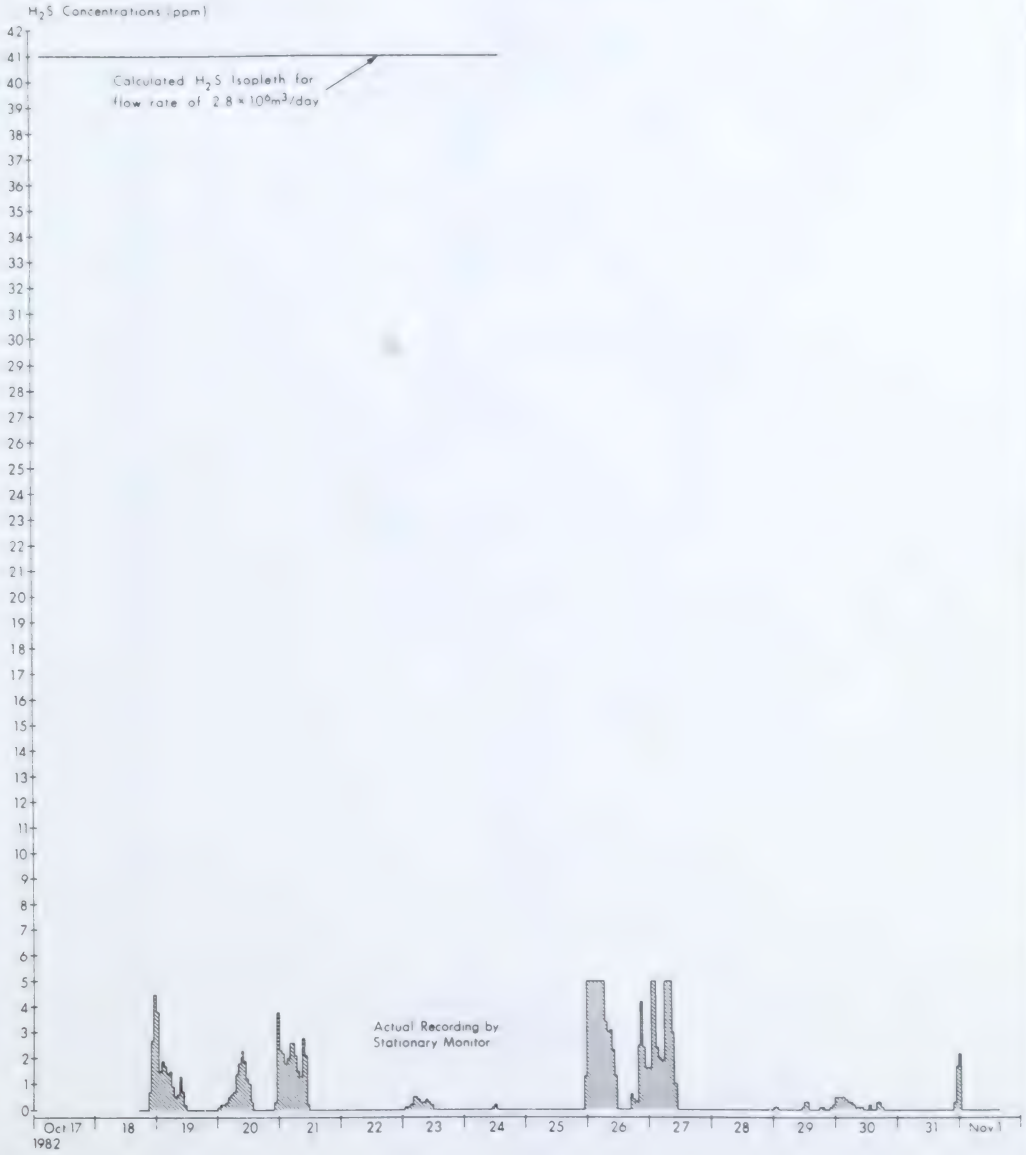

FIGURE A.6 H$_2$S CONCENTRATIONS RECORDED BY THE LODGEPOLE STATIONARY MONITOR. 17 October to 1 November, 1982.

H$_2$S concentrations greater than 5ppm recorded at Lodgepole by mobile monitor are summarized on table 7.1 of the report

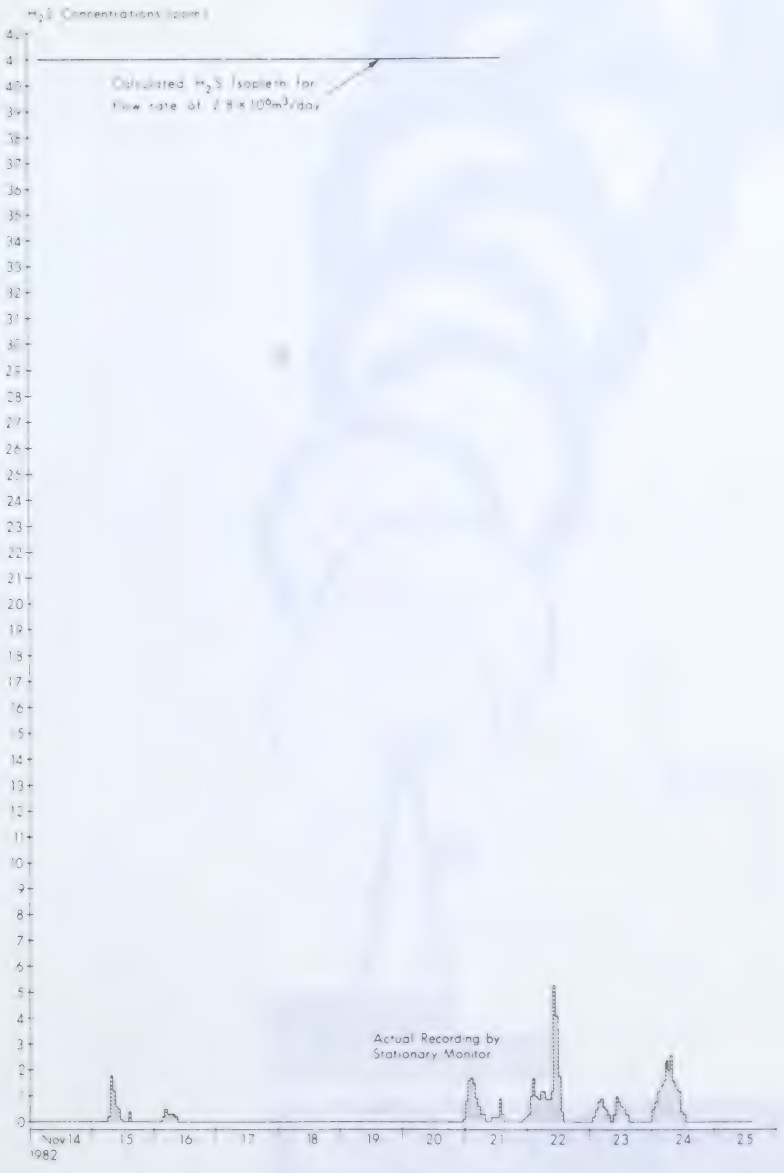

FIGURE A.7 H_2S CONCENTRATIONS RECORDED BY THE LODGEPOLE STATIONARY MONITOR
14 November to 25 November, 1982

H_2S concentrations greater than 5ppm recorded at Lodgepole by mobile monitor are summarized on table 7.1 of the report

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LODGEPOLE
Blowout Report

Summary and Recommendations
for Report D84-9

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LODGEPOLE BLOWOUT INQUIRY

PHASE 1 REPORT - SUMMARY AND RECOMMENDATIONS

WITH RESPECT TO AN INQUIRY HELD
INTO THE BLOWOUT OF THE WELL, "AMOCO DOME
BRAZEAU RIVER 13-12-48-12"

DECEMBER 1984

LODGEPOLE BLOWOUT INQUIRY PANEL

LODGEPOLE INQUIRY PANEL

SUMMARY AND RECOMMENDATIONS

The report concerns

The summary and recommendations of the Inquiry Panel respecting the blowout of the well, "AMOCO DOME BRAZEAU RIVER 13-12-48-12," which blew out of control on 17 October 1982.

Published December 1984

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SUMMARY

INTRODUCTION

17 October 1982 will likely be a significant date in Alberta's history. It was on that day at 14:30 that the well, AMOCO DOME BRAZEAU RIVER 13-12-48-12 (13-12 well), located 20 kilometres (km) west of the small hamlet of Lodgepole, blew out of control. For over 2 months specialists fought to regain control of the well and were finally successful on 23 December 1982.

People residing near the blowout were significantly affected by events during the 67 days. At times, the odours were severe and people feared for their health and safety. Even people far removed from the area were subjected to the unpleasant odours, depending on atmospheric conditions.

The blowout will likely have a significant impact on the Alberta gas industry, particularly with respect to drilling sour gas wells.

A public inquiry was convened to learn what happened, why it happened, and how it might be avoided in the future. The Inquiry Panel's (Panel) views on these questions are provided in this summary.

WHAT HAPPENED AT LODGEPOLE?

In August 1982, Amoco Canada Petroleum Company Ltd. (Amoco) applied to the Energy Resources Conservation Board (ERCB) for a licence to drill a well to be located 20 km west of the hamlet of Lodgepole, Alberta. The well was spudded on 10 August 1982 and was drilled to about 3000 metres (m) without significant incident. Intermediate casing was then installed prior to drilling into the expected productive formation. On 15 October, the drilling crew began coring into the zone and the first two cores were obtained without apparent problems. On 16 October, the crew proceeded with core No. 3, but halted coring operations when evidence of fluid influx from the formation was detected.

For the next 16 hours, the crew fought to regain control of the well but finally, at 14:30 on 17 October, the well blew out of control. In spite of numerous measures to regain control, the sour gas blowout persisted for 67 days with control finally being regained on 23 December 1982.

THE INQUIRY

On 14 January 1983, the ERCB announced that an inquiry would be held to determine the facts surrounding the Lodgepole blowout. The inquiry was held in two phases and this report deals with Phase 1, the analysis, findings, and recommendations regarding the blowout itself.

IMPORTANT ISSUES

As a result of several public pre-inquiry meetings with participants, the Panel determined that the following were the most important issues to be addressed:

> What were the factors contributing to the Lodgepole blowout and what actions were taken to prevent it? Were these actions adequate?
>
> What significant factors contributed to regaining control of the well? Were control actions adequate?
>
> Was there a hazard to human health and, if so, was the effect measurable? What steps were taken to minimize the effect and were the steps adequate?
>
> Was there an impact on the environment and, if so, how serious was it? What steps were taken to reduce the impacts and were the steps adequate?
>
> Were ERCB and Government department regulations, policies, and procedures adequate? Were the responses to the emergency following the blowout adequate?

Additionally, the Panel decided it should examine, quite separately from the 13-12 incident, the more general question of whether further actions should be taken to minimize the possibility of future blowouts in Alberta. That assessment took place following the main inquiry and the Panel's conclusions were provided in its Phase 2 report issued in April 1984.

WHAT WENT WRONG AT THE 13-12 WELL?

The drilling plan for the 13-12 well included cutting cores in the productive formation. While cutting the third core on 16 October, reservoir fluids, including sour gas, unexpectedly entered the wellbore resulting in what the industry calls a "kick". Amoco was unsuccessful in controlling the kick and after a 16-hour battle, totally lost control of the well on 17 October.

Why did the kick occur? Unfortunately, it is not possible to be certain as to all of the developments that occurred on 16 and 17 October. Nevertheless, the Panel's reconstruction of those events leads it to conclude that the initial kick occurred primarily because drilling practices during the taking of cores No. 2 and 3 were deficient and, when combined with the marginally adequate mud density being used, this permitted the entry of reservoir fluids into the wellbore.

The Panel also has concluded that the kick was likely not controlled because

(a) the drilling crew did not immediately recognize the problem and therefore did not immediately apply and maintain standard kick-control procedures,

(b) several pieces of vital equipment did not function properly, including:

   (i) casing pressure instruments,
   (ii) the degasser,
   (iii) drill pipe, and
   (iv) travelling block hook latch, and

(c) supplies of mixed drilling mud were not adequate during the kick-control operations.

In summary, the Panel concludes that no single element in the chain of events was the sole cause of the blowout. The unexpected entry of reservoir fluids into the wellbore was probably due to a combination of Amoco not adhering to sound drilling practices and only marginally adequate mud density. If the degasser had operated effectively, the initial kick might have been circulated out of the system, and subsequent kicks would likely have been avoided. Even with the failure of the degasser, control might have been maintained if there had been sufficient and properly weighted mud on hand to pump into the well. Additionally, if the casing pressure instruments had been operational from the outset, the crew might have recognized the kick at an earlier stage and implemented standard kick-control procedures when fluid influx was still relatively small. If the decision had been made to use hydrogen-sulphide- (H_2S) resistant pipe for the full drill string, the pipe might not have parted and the succession of kicks might still have been successfully circulated out. And finally, if the travelling block hook latch had not failed, it may have been possible to retain control of the well by "top kill" methods.

Were Amoco's actions satisfactory respecting these various developments? Amoco indicated that its program was based, from the outset, on the possibility but not an expectation of encountering sour gas. The Panel is satisfied that Amoco applied reasonable judgement with respect to the selection of the Nabors rig, approving the degasser, and to a lesser degree, in selecting the type of drill pipe to drill the well, even though, with hindsight, the latter two turned out to be inadequate for the conditions that developed. On the other hand, the Panel believes Amoco's actions were deficient with respect to:

(a) drilling practices during coring operations (cores No. 2 and 3),

(b) implementation of standard kick-control procedures,

(c) ensuring adequate mixed drilling mud was available at all times, and

(d) maintaining equipment in satisfactory operating condition (casing pressure instruments).

It appears to the Panel that the fundamental problem was that Amoco did not apply the necessary degree of caution while carrying out operations in the critical zone. Amoco did not appear to be sufficiently aware of the potential for problems that could occur when coring into the porous zone and thus the need to be fully prepared in the event of a fluid influx. Consequently, when a kick developed, there were delays in responding to it. Then, when equipment problems occurred and supplies of mixed mud were inadequate, Amoco was forced into further delays of precious time in implementing kick-control actions.

In summary, it is clear to the Panel that the major area of deficiency relates to the "human factor" which was so extensively referred to during the Phase 2 portion of the inquiry.

The Panel has made a series of recommendations aimed at reducing the possibility of future blowouts. Several have already been implemented, or are being studied. Anyone interested in the detailed assessment of the cause of the blowout, or the Panel's specific recommendations, is invited to review section 5 of the full report.

REGAINING CONTROL OF THE 13-12 WELL

It required 67 days to regain control of the 13-12 well. Why did it take so long?

The Panel believes that several factors were instrumental in the delay:

1 The well was particularly difficult to tame.

The flow rate from the well was much higher than originally estimated. Also, the flow contained large volumes of condensate and a high percentage of H_2S, both of which became serious inhibiting factors to regaining control. Indeed, the Panel believes it would be difficult to find a more serious and difficult blowout to control.

2 Weather conditions were frequently unfavourable.

Because of the high flow rate from the well, and its high H_2S content, work on the well was possible only when there was sufficient wind to disperse the gas. Frequently, atmospheric conditions were relatively calm, and for more than 8 days out of the 26 days that the well was not on fire, weather conditions at the well site prevented the control crews from working.

3 Amoco's safety procedures and equipment, while appearing to be typical for the industry, were not adequate to cope with the magnitude and type of emissions from this particular well. As a result, a serious accident interrupted an operation that might have been successful with a less difficult well, and resulted in a further well-control delay of 37 days.

Initially, Amoco and the ERCB had concluded that only two well-control options were available: capping the well while it was not on fire, or drilling a relief well. Since the relief well would take up to 3 months to drill, with no assurance of success when completed, it was judged to be a last resort. After Amoco and the ERCB became aware of the damage to the casing bowl from the second fire and significant effects that the sour gas well emissions seemed to be having on the general public, consideration was given to a third control option, capping the well while it was on fire. Evidence at the inquiry indicated that this technique had been used only six times worldwide, and only on wells that were much smaller "blows" than the 13-12 well. While both Amoco and the ERCB recognized the serious risks inherent in this procedure, it was nevertheless selected because of the special circumstances. It eventually proved successful, but required another 21 days before it could be completed.

The difficulties encountered in regaining control of the 13-12 well, and the resulting impacts on the public, amply demonstrate the need to avoid such situations in the future. Once a well has blown out of control, the options available to the well-control crew are limited. One of the benefits from the 13-12 experience was to learn that such a difficult well could be brought under control while it was on fire.

HAZARD TO HUMAN HEALTH

How did the emissions from the well affect the health of people residing in nearby regions?

The Panel heard evidence from 30 local residents, members of the Pembina Area Sour Gas Exposures Committee (PASGEC) at the formal inquiry, and 11 residents at the informal session, describing how the blowout had affected the health of members of their families. These effects were said to include headache, eye irritation, upper respiratory tract symptoms such as sore throat, nasal irritation, and nosebleeds in children, and lower respiratory tract symptoms, including pain on deep inhalation and some shortness of breath. The Panel also heard evidence from the Edmonton Area Respiratory Patients. Several of the PASGEC witnesses also referred to a similarity in the symptoms of illnesses in both people and livestock.

Various interpretations were placed on these submissions. Some participants at the inquiry contended that the problems related to a "flu epidemic", others to psychologically induced reactions. Others claimed that the noxious gas was the cause.

Unfortunately, there was a lack of scientific data available for analysis. Considering the large amount of circumstantial evidence, however, the Panel is satisfied that the well emissions did lead to at least short-term health effects for a substantial number of people, particularly in the Lodgepole area. The anecdotal evidence also strongly suggests that some people, especially those having respiratory problems, are much more likely to suffer unfavourable effects from H_2S gas.

What steps were taken by Amoco and Government agencies to protect the health and safety of persons living in the local area?

Although it was not set out in a single document, a protection plan was put in place which provided for:

(a) the establishment of a set of H_2S exposure limits designed to safeguard human health,

(b) the monitoring of actual H_2S concentrations throughout the area where people were residing, and

(c) arrangements for people to leave the area whenever H_2S concentrations exceeded the exposure limits. Where evacuation was deemed not practical, such as in Drayton Valley, the plan called for ignition of the well if H_2S concentrations exceeded the prescribed limits.

Exposure Limits

The protection plan was designed to ensure that if an H_2S concentration of 15 parts per million (ppm) was reached in any area where people were residing, then they would leave the area. Additional standards were identified for persons described as "sensitive", which generally was taken to mean persons with respiratory problems, very young children, the elderly, and pregnant women. However, for various reasons, these additional standards, while acknowledged, were not actually applied.

The appropriateness of the H_2S exposure limits was extensively debated at the inquiry. Particular concern was expressed about the need for much stricter standards for those persons judged to be more susceptible to H_2S.

The Panel recognizes the concerns about the standards, particularly regarding more stringent standards for sensitive people, and has recommended that this matter be given further consideration by the Provincial Board of Health (PBOH).

Monitoring H_2S Concentrations

The air monitoring program to determine actual H_2S concentrations in the general Lodgepole area was under the direction of Alberta Environment (AE). Stationary air monitors were installed in the nearby communities of Cynthia, Lodgepole, and Drayton Valley, and at the Brazeau Dam. Five mobile air monitors, four of them operating 24 hours per day, were used to check rural areas. Under the plan, three of the mobile monitors followed the highest H_2S concentrations as the plume moved through the area.

The monitoring data gathered during the event shows that the dispersion of the gas cloud from the well was actually quite rapid, notwithstanding the large volumes of H_2S gas being emitted. For example, no concentrations in excess of 10 ppm were found at any residences located farther than 20 km from the well, and there were only a few instances inside that 20-km radius. The highest concentration recorded at Cynthia was 14 ppm, at Lodgepole 14.5 ppm, and 5 ppm at Drayton Valley, some 45 km from the well. The highest reading in Edmonton was 0.5 ppm.

Throughout the 26-day period that the well was not on fire, H_2S concentrations were generally low. For example, at Lodgepole, the concentrations were less than 1 ppm for 87 per cent of the recorded hours, while at Cynthia and Drayton Valley they were less than 1 ppm for about 95 and 96 per cent of the time, respectively. In Edmonton, though the odour was detected, the H_2S concentrations were actually less than 0.1 ppm for 93 per cent of the time.

Evacuation

There were six occasions during the 26-day period that the well was not burning when concentrations at local residences reached the evacuation level of 15 ppm. All of these cases were in rural areas. Where they occurred, the people were notified and they left the area on a temporary basis. Additionally, Amoco advised that it was prepared to pay the costs for people who wished to leave the area because of effects from the emissions. A total of 28 individuals plus 4 families left on the basis of the Amoco offer.

IMPACT ON THE ENVIRONMENT

How serious was the environmental impact from the well emissions?

During the 67 days the well was out of control, there were daily emissions to the atmosphere of 150 to 450 tonnes of sulphur and 300 to 1100 cubic metres (m^3) of condensate. For the 26 days the well was not on fire, the condensate fell on the area immediately surrounding the well site and had an impact that was initially like that of an oil spill. Subsequent fires caused the lease area to be extensively burned. While this destroyed vegetation over a large area, it reduced long-term condensate pollution problems. During the period the well was on fire, the sour gas and condensate was combusted in the extremely intense fire and the H_2S was converted to sulphur dioxide (SO_2).

Obviously, emissions of that magnitude are certain to have some environmental impacts. Several studies were made to evaluate the extent of the impacts and the results were submitted to the inquiry. An area of some 300 hectares (ha) surrounding the well was the most seriously affected. There were major impacts on vegetation and soils in that area and minor impacts on surface water, groundwater, benthic organisms, mammals, and birds. Some of these impacts were ameliorated by quick remedial action. Due to the presence of residual condensate on the vegetation outside the burned and cleared areas and in the ground right around the well, there will continue to be impacts near the well site for some years on trees, groundwater, and soil.

To overcome the major impacts in the vicinity of the well, a program of short-term remedial measures and longer-term reclamation has been established. The program is comprehensive and should permit successful rehabilitation of the impacted area.

Sulphur emitted from the well, primarily in a gaseous form, was eventually deposited in low concentrations on the ground over an area of hundreds to thousands of square kilometres. There is no evidence that these levels of sulphur deposition will have long-term harmful effects on soils, vegetation, or water bodies.

RESPONSES BY ERCB AND GOVERNMENT DEPARTMENTS

Were ERCB and government regulations fully complied with during both the drilling and control operations at the 13-12 well?

Were the responses by the ERCB and Government departments appropriate during the emergency especially in terms of protecting the public?

The Panel did not find any evidence that Amoco had, in any significant manner, contravened either ERCB or government regulations. However, it did find that those regulations and policies need strengthening in several areas as they relate to the drilling of critical sour wells.

The Panel has made specific recommendations in several sections of this report to achieve that objective.

The Panel concluded that the response by the ERCB and Government departments was generally adequate, although improvements could be achieved particularly in the co-ordination of emergency response activities. A glaring deficiency by all parties related to communication with the public and the media during the blowout period. It was generally conceded by participants that efforts in this respect had been unsatisfactory and that major improvements were needed. The Panel believes that many of the problems relating to the public, that occurred during the incident, were directly attributable to inadequate communication. The Panel has recommended that a specific communication program be developed so that, in the event of another incident, the public can be kept properly informed and can have its concerns more effectively addressed.

WHAT ABOUT THE FUTURE?

One of the objectives of the inquiry was to identify actions which might be taken to significantly reduce the possibility of a future "Lodgepole". In order to consider that question, the Panel arranged for a separate phase of the inquiry (Phase 2) to consider evidence from drilling industry experts on how blowouts might be reduced. That phase resulted in a substantial number of recommendations by participants, most of which the Panel endorsed in its Phase 2 report, and which the ERCB is pursuing in conjunction with industry. Several of those recommendations are already in effect, although some are on a preliminary or trial basis only.

In its two inquiry reports, the Panel has made many recommendations that relate to drilling, well control, and impacts on the public. The important question is whether those recommendations, if implemented, would significantly reduce the likelihood of future blowouts. To test that proposition the Panel has, in section 13 of the full report, reconstructed the 13-12 case, but has assumed that its various recommendations were in place and operating effectively prior to the licensing of the well.

From its test of this proposition, the Panel is reasonably certain the 13-12 blowout could have been avoided. Implementation of the Panel's recommendations can significantly reduce the number of blowouts in Alberta, provide some assistance in regaining control of any well where a blowout has occurred, and would play a major role in assisting the public during a blowout. Obviously, major attention should be directed to avoiding blowouts. To that end, the Panel's recommendations include changes in equipment, changes in procedure, and the strict observance of prescribed or accepted operating practices. Particular emphasis needs to be placed on the "human factor" which appears to be a root cause of blowouts. The Panel believes that an effective means of reducing the impact of human factor problems would be to require that operations in the critical zone be conducted in a very cautious and careful manner. To achieve that objective will require the commitment and direction of senior management of those companies drilling critical sour wells. The ERCB can assist by strengthening its inspection procedures and regulatory requirements.

CONCLUSION

The Panel's findings indicate that the 13-12 blowout could probably have been avoided, even allowing for equipment failures, if Amoco had followed a policy of cautious drilling in the critical zone and if Amoco had been better prepared to deal with unexpected developments. The public was understandably concerned, frightened, and angry about the blowout. Two workers lost their lives, and the public experienced widespread and unpleasant health effects. While the evidence suggests to the Panel that the actual long-term physical effects were relatively minor, the legacy of the Lodgepole blowout will permeate the Alberta scene for many years. This is a matter that will require special attention by industry, the ERCB, and Government departments. Special efforts must be made by all parties to avoid another occurrence, if at all possible, and to more effectively handle events should another major well blowout ever occur.

The Panel has made many recommendations that, if fully implemented, can significantly reduce the number of blowouts. Special emphasis has been placed on critical sour wells. Several of the recommendations relate to a review of drilling equipment, but the primary emphasis has been placed on the need to reduce blowouts caused by human error. The Panel has reviewed the inquiry reports issued earlier this year for the blowout at the SHELL ET AL UNIACKE G-72 well[1], off the east coast of Canada, and the loss of the Ocean Ranger[2] drilling rig. It also has reviewed the previous ERCB report on the blowout of the well, AMOCO PACIFIC BRAZR 7-10-48-12 (7-10 well), which occurred in the same area only 5 years prior to the 13-12 blowout. Each of these three reports indicates that a combination of equipment and human factor causes were responsible for the failures. In each case, the relevant inquiry panel, either directly or indirectly, indicated that the failure probably would not have occurred had appropriate practices been followed, notwithstanding the equipment problems. These conclusions are very similar to those for the 13-12 well.

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[1] Report of Investigation of Events Culminating in a Blowout of Gas and Condensate at Shell Et Al Uniacke G-72.

[2] Royal Commission on the Ocean Ranger Marine Disaster – Report One.

The question, then, is how can human factor problems be significantly reduced in drilling operations? The Panel believes that the most effective way would be to ensure that drilling personnel:

(a) are well trained,

(b) are at all times conscious of potential problems, and ready to deal with them,

(c) are properly supported by technical assistance,

(d) follow a sound and safe drilling plan, and

(e) proceed with operations in a cautious manner, particularly while operating in critical zones.

The primary responsibility for ensuring that these objectives are achieved lies with industry and, in particular, with the company that has been issued a licence to drill. Several of the Panel's recommendations address these issues.

The Panel also believes that the ERCB has a responsibility to test whether these objectives are being achieved, and in that regard believes that the ERCB inspection system should be carefully reviewed to determine how it can be strengthened to minimize human factor problems.

RECOMMENDATIONS

THE CAUSE OF THE BLOWOUT AND THE ADEQUACY OF AMOCO'S ACTIONS

1 The following types of equipment should be examined for design, capacity, and operational problems to ensure that they are adequate for worst-case conditions:

   (a) degasser,
   (b) casing pressure instruments,
   (c) travelling block hook latch,
   (d) kelly hose,
   (e) blowout preventers (BOP), and
   (f) equipment for anchoring drill pipe.

2 The BPRC should examine the impact of H_2S, and how to avoid those impacts on:

   (a) drill pipe,
   (b) external BOP components, and
   (c) BOP master controls.

3 The industry and ERCB should take any action necessary to ensure that drilling operations are carried out in a cautious manner, particularly in the critical zone of critical sour wells. Special procedures should be developed, documented, and used for operations in the critical zone. These would include detailed instructions respecting tripping in, tripping out, coring, testing, and other operations where particular care is required.

4 Standard kick-control procedures should be reviewed to determine whether they allow for situations where equipment failures or other unexpected events occur during control operations.

5 The adequacy of the current training programs for drilling personnel should be reviewed and, in particular, consideration should be given to ensuring that they are effective in ensuring crew familiarity with kick recognition and control.

6 Consideration should be given to the need to have special expertise available while operations are being conducted in the critical zone of critical sour wells.

7 The ERCB should review its inspection system and, in particular, it should conduct special inspections of critical sour wells immediately prior to entry of the critical zone and while drilling in it, to ensure that operations are being conducted in a cautious manner and consistent with proper procedures.

8 Mud system design and operation should be reviewed respecting density, system capacity, back-up supply, scavengers, and impact of H_2S on mud and the ability to pretreat and recondition it.

9 Occupational Health and Safety Division of Workers' Health, Safety and Compensation (OH&S) should consider amending its regulations to ensure that breathing apparatuses are available for all individuals that may be at a rig, including extra people called in for an emergency.

WELL-CONTROL ACTIVITIES AND THE ADEQUACY OF ACTIONS BY AMOCO AND OTHERS

1 The ERCB and the involved operator should make a serious effort at the outset of any blowout to ensure that the flow rate and other characteristics are estimated as accurately as possible, and that the estimates and the expected weather conditions are properly recognized in planning for control of the well.

2 The ERCB should formalize, to a greater extent, its involvement in decisions related to intentionally igniting blowouts and the possible drilling of relief wells. A process should be developed that would ensure that public concerns are properly considered in making these decisions, and the reasons for the decisions are communicated to the public.

3 OH&S should give consideration to the establishment of a committee to be concerned with protecting workers in toxic gas environments such as would result from episodes like the 13-12 blowout. Such a committee might be composed of experts on safety and rescue drawn from OH&S, the petroleum industry, the ERCB, and the Calgary and Edmonton fire departments. These individuals, or a team which they could assemble, could be readily available to act as advisers or participants in the management of the safety aspects of particularly dangerous situations in the petroleum industry. With respect to the prevention of serious accidents, they could assist in reviewing current and future safety and rescue practices and safety educational programs.

4 OH&S should give consideration to the development of an adequate, possibly compulsory, training program for workers who might encounter H_2S or other toxic gases in substantial amounts. This training would be needed prior to their involvement at a well site or other potentially dangerous locations. This training should emphasize practical matters such as familiarization with and the wearing of a self-contained breathing apparatus. Through such a program, workers who are physically or psychologically unsuitable for work in such hazardous environments, or while wearing masks, would likely be identified.

5 The ERCB should investigate the availability and limitations of blowout insurance. The Panel understands that the matter of insurance is being looked at by the ERCB as a result of the Phase 2 report.

6 The ERCB should consider how the experience and expertise needed to control a blowout would always be available when required, even by a small organization.

7 OH&S should pursue the development of clearly distinguishable names for all types of masks to be used in the presence of various concentrations of H_2S.

8 Consideration should be given by industry and the ERCB to the development of a workshop or seminar to consider technical matters related to the control of wild wells.

HAZARD TO HUMAN HEALTH

1 The Provincial Board of Health (PBOH) should reconsider its H_2S exposure limits in light of the Lodgepole evidence and, in particular, for "sensitive individuals".

2 Information should be obtained by the PBOH on the biological effects of extended intermittent and continuous exposure to moderate and low-level concentrations of H_2S, such as were experienced by residents and animals during the Lodgepole blowout. This could be obtained by modern research techniques.

3 AE, the ERCB, and representatives from industry and the public should develop a comprehensive centrally dispatched air monitoring plan that could be implemented immediately when needed.

4 AE and the ERCB should arrange for a comparison and analysis of actual H_2S concentrations obtained by monitors and the predicted concentrations from dispersion modelling, with the objective of improving the latter capability.

5 Further consideration should be given by the PBOH and other medical bodies to whether useful information could be obtained from a review of actual medical experience during the blowout, and to consider whether better measures can be implemented to determine the effects of emissions from other blowouts which may occur in the future.

6 Methods of providing remote rural residents with Drager units and possibly crush ampoules, and training in their use, should be addressed in site-specific emergency response plans.

7 The ERCB should attempt to identify all of the gaseous contaminants, in addition to H_2S and SO_2, which could be produced by a sour gas well, since other components could also have biological significance. This type of physical chemical analysis could be carried out on material safely obtained from an existing well or wells.

IMPACT ON THE ENVIRONMENT

1 AE and other appropriate Government departments should establish a protocol for improved sampling and analysis of soil and vegetation that would provide a means of evaluating impacts of sour gas releases on soils and vegetation if a blowout occurs in future.

2 Alberta Forest Service (AFS) should co-ordinate long-term monitoring of impacts on the biosphere in the "on-site and immediate" area of the 13-12 well, plus adjoining areas of the blowout, as defined in the full report.

3 Alberta Agriculture (AA) should develop a protocol to enable the gathering of timely and relevant data on agricultural activities if another serious sour gas release occurs.

4 AA should consider conducting an on-going examination of livestock in the general blowout area to determine if effects of long-term exposure to H_2S can be found.

5 The ERCB, the industry, and appropriate Government departments should consider ways of dealing with concerns of the public respecting monetary impacts on the public resulting from sour gas blowouts.

6 The ERCB and AE should arrange a symposium to hear expert views on plume modelling/plume impingement and sulphation ground sampling analysis techniques.

COMMUNICATION AND CO-ORDINATION

1 A model communication program, along the lines suggested in section 9.4 of the full report, should be developed by appropriate Government departments and agencies with input from the public and industry.

2 The "Peacetime Emergency Operations Plan For a Sour Gas Release", recently issued by Alberta Disaster Services (ADS), should be reviewed in light of the Panel's recommendations.

3 The establishment of a "command post" organizational structure should be confirmed and implemented for all significant blowouts.

ADEQUACY OF ERCB'S RESPONSES FOLLOWING THE BLOWOUT, AND ITS REGULATIONS, POLICY, AND PROCEDURE

1 The ERCB, with appropriate input from industry, the public, and other Government departments, should identify wells which are "critical" in terms of avoiding possible blowouts and establish special conditions that must be satisfied by an operator before these wells can be drilled. The ERCB should advise other government agencies of all licences issued for critical wells.

2 The ERCB and other involved Government departments should establish a plan for their involvement in future emergencies such as the 13-12 well. The plan should include, among other matters, details regarding the responsibilities of various parties, standards for notification and evacuation, and plans for communication with the public and the media. Care should be taken that appropriate municipal officials are aware of the plan.

3 Special efforts should be made to more accurately estimate the potential H_2S release rate for a critical sour well.

ADEQUACY OF THE GOVERNMENT DEPARTMENTS' RESPONSES FOLLOWING THE BLOWOUT, AND THEIR REGULATIONS, POLICY, AND PROCEDURE

1 A government emergency response plan should be put in place for dealing with sour gas releases in the province. Such a plan has been prepared by ADS on an interim basis and will be reviewed in light of this report, comments from the public, and other involved parties. It should be maintained on a current basis. The final plan should address all significant matters relevant to serious sour gas releases and in particular the following:

(a) the responsibilities and authorities of various departments and agencies,

(b) the need for a control and communication centre,

(c) procedures to obtain the best possible estimates of gas flow and composition data,

(d) the availability of suitable equipment for monitoring,

(e) ways in which to make communications with the public and media more effective,

(f) standards, notification, and evacuation criteria and procedures,

(g) the decision process with respect to possible ignition of wild wells,

(h) the collection of data for health research purposes, and

(i) impact of sour gas on animals and crops and ways of better advising rural people respecting these matters.

The public should have the opportunity for input to the plan and should be made aware of its existence when it is in place.

2 OH&S should review its procedures and regulations respecting the suitability and number of breathing apparatuses, the training of workers in their use, review procedures for dealing with workers' health and safety matters for sour wells, and develop a program of direct involvement by senior OH&S staff to be implemented in the event of a blowout. This might be done through a series of workshops.

3 The PBOH should review existing H_2S exposure standards, particularly as they relate to sensitive individuals, in light of experience gained from the Lodgepole blowout.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

UNIVERSITY OF ALBERTA
GOV'T DOCS
AUG 0 9 1984

ALBERTA ENERGY COMPANY LTD.
PROPOSED PIPELINES AND RELATED FACILITIES
COLD LAKE - EDMONTON AREAS

Decision D 84-10
Applications 840117, 840118, and 840119

1 INTRODUCTION

1.1 The Applications

Alberta Energy Company Ltd. (AEC) applied pursuant to Part 4 of the Pipeline Act for permits to construct pipelines and related facilities, and for approvals to modify and alter existing pipelines and facilities to transport increased volumes of diluent from Edmonton to the Cold Lake area and blended bitumen from the Cold Lake area to Edmonton. The diluent would be blended with bitumen to permit efficient transport of the bitumen by pipeline. Figure 1 shows the locations of some Cold Lake area bitumen projects; existing, approved, and proposed pipelines; intervener lands; and certain geographic features.

Application 840117 is for a permit to construct approximately 2.0 kilometres (km) of 323.9-millimetre (mm) outside diameter (OD) pipeline and related facilities, consisting of a new suction pipeline from the Interprovincial Pipelines Ltd. (IPPL) tank farm in legal subdivision 6 of section 5, township 53, range 23, west of the 4th meridian, to the existing AEC Strathcona pump station in Lsd 9-6-53-23 W4M, and a new discharge pipeline from the pump station to connect with an existing AEC 323.9-mm OD pipeline at Lsd 6-5-53-23 W4M. Diluent would be pumped from the IPPL tank farm to the Cold Lake area using the existing 323.9-mm OD pipeline. The change of service proposed for the 323.9-mm OD pipeline from blended bitumen to diluent is described below.

Application 840118, as amended, is for a permit to construct approximately 6.09 km of 219.1-mm OD pipeline and related facilities to transport diluent from the Ardmore Junction in Lsd 16-24-64-4 W4M to a meter station situated in Lsd 11-12-65-4 W4M, adjacent to the Esso Resources Canada Limited (Esso) Cold Lake Production Project (CLPP) facilities. At the CLPP facilities the diluent would be blended with bitumen prior to the blend being pumped to Edmonton.

Application 840119, as amended, is for a permit to construct approximately 6.09 km of 406.4-mm OD pipeline from a proposed 3000 kilowatt (kW) pump station and metering facility in Lsd 11-12-65-4 W4M (AEC CLPP pump station) to the Ardmore Junction, and approximately 241.9 km of 610.0-mm OD pipeline from the Ardmore Junction to the IPPL Edmonton pipeline terminal in Lsd 2-5-53-23 W4M. Blended bitumen from the Esso CLPP would be pumped to the Ardmore Junction, combined with blended bitumen produced at the Esso Leming and May-Ethyl pilot projects, and transported to Edmonton.

Application 840119 is also for approvals to make piping modifications and increase the power of the Strathcona pump station to 2685 kW to pump diluent to the Cold Lake area, change the direction of flow and fluid transported from blended bitumen to diluent in the existing 323.9-mm OD pipeline from the Ardmore Junction to Edmonton, and increase the power of the AEC Leming pump station located in Lsd 14-5-65-3 W4M to 1566 kW.

1.2 The Interventions

Dome Petroleum Limited (Dome) and Esso supported the AEC applications. Esso said the pipelines would be needed to transport bitumen produced by Phases I-IV of its CLPP.

Genstar Corporation and Genstar Gypsum Limited (Genstar) intervened because they believed the proposed AEC pipeline might prevent future expansion of the gypsum wallboard plant and facilities. Genstar was concerned about locating the AEC pipeline in the existing pipeline tunnel, and suggested routing the proposed AEC pipeline to the east of existing pipelines that cross its lands (see Figure 2).

Industrial Realty Services (Strathcona) Limited (IRS), representing several landowners along the route, was concerned about the construction methods proposed by AEC. Specific concerns included "the non-removal of top soil within the working area", impacts to drainage ditches, foreign material left after construction, and safety. At the hearing, IRS indicated that it had discussed its concerns with AEC and was now satisfied that AEC's construction specifications would adequately address its clients' concerns.

Dr. C. S. Shirvell and Dr. H. Simmons were concerned about the effect that pipeline construction across their respective lands would have on agricultural productivity. Dr. Shirvell contended that the proposed pipeline would restrict the use of his property, not only for farming, but also for other uses that he was considering. Drs. Shirvell and Simmons were also concerned about the crossing of Ross Creek.

Alberta Environment (Crown) questioned AEC about the route through the Bellis natural area, the crossing of Manatokan Creek, proposed soil conservation techniques, and other environmental matters.

1.3 The Hearing

G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng., considered the applications at a public hearing in Edmonton, Alberta, on 15 and 16 May 1984. Those who appeared at the hearing are listed in the appendix.

2 ISSUES

The Board believes the issues are:

- the purpose and necessity of the proposed pipeline
- the pipeline route
- environmental impacts
- agricultural impacts
- the crossing of the Genstar lands
- pipeline design, construction, and operation

3 PURPOSE AND NECESSITY

3.1 AEC's Views

AEC indicated that the proposed line was necessary to provide pipeline service for bitumen producers in the Cold Lake area. It stated that the applied-for pipelines and facilities would increase the capacity of the system from its current throughput of approximately 4000 cubic meters per day (m^3/d) of blended bitumen to approximately 20 000 m^3/d. AEC said that the expanded pipeline would be able to transport blended bitumen produced by the Esso Leming and May-Ethel experimental projects, the Suncor Fort Kent project and the approved BP Exploration and Petro-Canada Wolf Lake and Esso CLPP Phases I-IV projects. The applicant advised that BP and Petro-Canada have finalized an agreement respecting an application to construct a lateral to the Wolf Lake project, and indicated that negotiations are being carried on with Dome and Suncor to supply bitumen to the pipeline.

3.2 Interveners' Views

Esso and Dome supported the need for the pipeline facilities to move bitumen from the Cold Lake region to Edmonton.

Dr. Shirvell claimed that there was no evidence in the application to support the need for the proposed pipelines and facilities and that the project had not been shown to be in the public interest. He further contended that viable alternatives for transporting the bitumen such as by trucks or rail had not been considered. However, Dr. Shirvell did not present any evidence concerning these alternatives.

3.3 Board's Views

From the evidence, the Board believes the proposed pipeline facilities will be needed to transport bitumen from existing and planned commercial and pilot projects in the Cold Lake area to the Edmonton area for further processing or movement to other markets.

The Board is also satisfied that the pipeline capacity that would result if the proposed facilities are built, would be sufficient to accommodate the production that can be reasonably anticipated from the Cold Lake area, and is of the opinion that there would be sufficient diluent available to blend with the bitumen to be transported.

4 ROUTE

4.1 AEC's Views

AEC stated that the 610-mm OD blended bitumen pipeline proposed from the Ardmore Junction to the Northeast Edmonton Pipeline Corridor would be located within its present 30-metre (m) right of way, and from that point to the IPPL pipeline terminal, a 5-m right of way parallel to existing pipelines would be used. From the Ardmore Junction to the CLPP, a 25-m right of way would be required to permit a 15-m separation needed between the blended bitumen pipeline and the diluent line because of the difference in operating temperatures of the two pipelines. AEC claimed that its proposed route minimized land fragmentation, reduced the proliferation of rights of way, and prevented unnecessary land disturbance by utilizing existing rights of way and following pipeline corridors.

The company also mentioned that it had held community meetings to inform landowners and occupants about its plans to expand the system, to discuss pipeline construction and operation details, and to hear any individual concerns about the project. The rights required for 94 per cent of the parcels of land along the pipeline route had been obtained by negotiation, and the remainder were being actively sought. In summation, AEC maintained that the use of existing right of way and pipeline corridors as proposed for its project constituted orderly development, and requested that the routes proposed be approved by the Board.

4.2 Interveners' Views

Dr. Shirvell objected to the proposed pipeline crossing his parcel of land, and suggested that the application should be denied because the selected route was not the optimum one and the applicant had not submitted any alternatives. He requested that the pipeline be rerouted around his land, and cited an example of a similar rerouting further to the north on another landowner's property. Dr. Shirvell pointed out that the Board had, on previous occasions, allowed route deviations because of special circumstances. He believed that such rerouting was justified in his situation because of the small size and nature of his property, and the fact that his property was being rendered useless by the proliferation of pipelines across it.

Dr. Shirvell also questioned the fairness of the method for acquiring the right to cross his property, and requested that the Board make it a condition of any permit issued, that the entry onto his land be negotiated with him.

Dr. Simmons stated that she too was opposed to another pipeline across her land, and indicated that she would prefer an alternative route around her property. Under cross-examination, Dr. Simmons said that her property was considerably larger than Dr. Shirvell's, and added that her major concerns related primarily to the agricultural and environmental disturbances caused by pipelines.

4.3 Board's Views

The Board believes that public interest is best served when pipeline routes minimize land fragmentation and utilize existing rights of way as far as practical. In this case, the Board notes that the majority of the route will be within the applicant's existing right of way, and most of the remaining portion of the route will be within a pipeline corridor parallel to existing lines.

Dr. Shirvell's request to have the pipeline right of way rerouted around his land was dealt with at length by the Board in an earlier decision (Decision 82-22). The Board recognizes that the earlier decision to have the pipeline route follow the railway route, thus minimizing the number of linear disturbances, has resulted in several pipelines crossing Dr. Shirvell's small piece of land. However, the Board did not receive any evidence which would cause it to conclude that it would be in the public interest to reroute the proposed pipeline around Dr. Shirvell's or Dr. Simmons' property.

The Board is of the view that section 11(2) of the Pipeline Act, whereby the Board may prescribe that entry onto property be obtained only by negotiation with the landowner, is intended to permit accommodating very special public interest concerns. The Board does not agree with Dr. Shirvell's view that such a condition is justified for the subject applications.

The Board also believes that the rights of way widths selected by AEC are appropriate, bearing in mind that the most of the pipeline route is along existing rights of way. The Board is also satisfied that AEC has requested the minimum widths required for proper construction and subsequent operation.

In summary, the Board is satisfied with the route proposed.

Additional views on agricultural impacts are included in section 6.

5 ENVIRONMENTAL IMPACTS

5.1 AEC's Views

In its statement on environmental impacts, AEC said that it was currently reviewing and preparing detailed environmental protection procedures to be included in the construction contract documents. AEC's proposed environmental protection procedures, were outlined in a number of documents filed at the hearing, and subsequent questioning by interveners dealt with certain specific items in the procedures.

In response to counsel for Drs. Shirvell and Simmons, AEC stated that Ross Creek, which is classed as a minor stream, would not be dealt with any differently than major streams. AEC further stated that the reclamation standards and procedures would be the same for all designated crossings and that the environmental standards and procedures specified would depend upon the category of stream being considered and any site-specific considerations that were involved. In response to the Crown's questions regarding Manatokan Creek, the applicant outlined the special precautions and procedures that would be followed to ensure bank stability and reclamation.

AEC also stated that there was no way it could avoid clearing the remaining 7 m of the 30-m right of way even in the environmentally sensitive Bellis natural area, because of the working space needed to install the pipeline. Regarding revegetation, AEC said that discussions had been held with environmental regulatory authorities and a revegetation program had been agreed upon.

AEC also addressed specific concerns of IRS, stating that agreement had been reached concerning debris clearing on landowners' property. To see that this was carried out, specific terms and conditions would be written into the construction documents.

On the matter of inspection, AEC confirmed that it intended to employ a full-time environmental inspector who would be responsible for seeing that all environmental regulations and procedures were followed by the contractor in accordance with construction plans. AEC stated that if changes by the contractor were required, the environmental inspector would normally work through the chief inspector to have the appropriate changes made; however, he would not be in a position to shut the job down.

5.2 Interveners' Views

Dr. Simmons noted that Ross Creek crosses her property, and outlined her concerns regarding environmental and reclamation procedures involving the pipeline crossing. Although Ross Creek is not considered to be a major stream, she asked that it be given proper consideration and that crossing techniques appropriate to a stream designated as a navigable watercourse be used. Dr. Shirvell expressed similar concerns.

IRS was concerned about debris and foreign material that might be left on the right of way across two of its clients' properties, and requested that such materials be removed upon completion of construction.

5.3 Board's Views

The Board believes that AEC should take special care and employ the latest pipeline construction techniques to ensure minimum environmental disturbance at Manatokan Creek, Ross Creek, and the Bellis natural area. Special surveillance of the crossing and reclamation procedures to be used both for Manatokan Creek and Ross Creek, and of the additional tree clearing required in the environmentally sensitive Bellis natural area, are necessary. The Board does not see these concerns as serious enough to deny the application but intends to communicate them to Alberta Environment, and to recommend that it have a representative available during construction at these particular locations.

Regarding other environmental matters, the Board is satisfied that AEC's general plan and procedures as submitted, together with the employment of a full-time environmentalist, will adequately accommodate the concerns. The Board is of the opinion that proper communication between AEC's environmentalist and landowners along the route is essential to see that environmental problems do not occur.

6 IMPACT ON AGRICULTURE

6.1 AEC's Views

AEC briefly outlined its proposed program for topsoil conservation and indicated that its procedures were to be different on agricultural lands than on lands used for pasture. AEC said an environmental and agricultural adviser would be working in a co-ordinating role along with the pipeline inspector to see that any special concerns of landowners would be looked after. In addition, AEC plans to have a land agent available on each of the construction spreads who would be in contact with landowners and ensure any agricultural concerns are conveyed to the company's expert adviser for resolution with the landowners involved. AEC undertook to have its land agent inform the landowners that "there is an individual they can talk to if they have concerns."

AEC took exception to the request by some interveners that an independent agrologist be retained by the Board. It contended that the environmental specialist that it would have on the job site would be a fully qualified professional, and there would be no need for an independent expert. AEC also objected to the suggestion that right of entry to lands be obtained by negotiation with the owner, maintaining that there was no evidence presented to support this request.

In answer to some interveners' concerns related to soil problems caused by winter construction, AEC emphasized that pipeline construction was scheduled to be completed before the winter months and that such concerns were not warranted.

6.2 Interveners' Views

Dr. Shirvell, with the aid of Mr. Crepin, his expert witness, made reference to a number of problems on agricultural lands that could be attributed to pipeline construction. He cited such matters as changed soil composition due to improper handling of topsoil and subsoil, increased pH in the soil, and higher compaction over the right of way leading to crusting of the soil, temperature effects, and other changes in characteristics. The cumulative effect of these changes was, he claimed, a reduction in soil fertility. To prevent these impacts, Dr. Shirvell requested that an independent agrologist be hired by the Board to determine the depth of topsoil to be stripped, to supervise reclamation methods and procedures, and to stop pipeline construction when the ground was wet or frozen. He also requested that a separate appeal procedure be made available to landowners if individual concerns were not properly looked after. On the matter of notification prior to construction, Dr. Shirvell requested that AEC supply him with a construction schedule in advance of the work so that he would know when the pipeline would cross his land.

Dr. Simmons had many of the same concerns as Dr. Shirvell, and was particularly anxious about the matter of improper mixing of topsoil and subsoil during pipeline construction across her land. She was also of the opinion that an independent agrologist would help to reduce undesirable impacts on soil productivity. Commenting on problems related to pipeline construction on her land, Dr. Simmons observed that in the past she had been unable to obtain satisfactory answers or corrective actions from company agricultural experts. She requested that if she had concerns, proper communication arrangements should be made available to her, and that procedures should be in place whereby prompt corrective actions might be taken. Through counsel, Dr. Simmons also supported the idea of AEC providing landowners with a construction schedule so that they would have some idea of when construction would occur across their lands and be in a better position to deal with site-specific problems.

IRS was concerned mainly with topsoil conservation during pipeline construction, and sought assurance from AEC that the procedures employed would not be detrimental to the landowners' interests.

6.3 Board's Views

The Board notes that the construction techniques proposed by AEC are industry-accepted practices. It is satisfied that good soil conservation can be achieved if the proposed environment protection plan is followed. The Board recognizes the various factors listed by Dr. Shirvell's expert witness that may affect soil fertility, and realizes that complete restoration of the soil to its original condition may not always be possible. However, the Board expects that this would be balanced by fair compensation to the landowner.

The Board does not agree with Dr. Shirvell that it should engage an independent agrologist to oversee construction practices. In the Board's view, the full-time soils and environmental expert that AEC will have on the project should provide the means to oversee, monitor, and advise on specific topsoil conservation procedures during the construction and reclamation phases. Such a person would also be available to deal with the concerns of individual landowners.

In order to ensure that a proper communication procedure exists to deal with specific complaints in a timely manner, the Board will require AEC, prior to commencement of construction, to inform landowners directly affected of the names of its land agents as well as the best method to contact those individuals. The Board, in keeping with a suggestion by Drs. Shirvell and Simmons, will also require that AEC inform all landowners along the route as to when construction will take place on their lands. This might be done when the landowners are advised of the names of the AEC land agents. Where substantial changes in a schedule occur, this also should be communicated to the landowners. The Board strongly believes that if all parties are aware of when construction will occur and who to contact if problems arise, many problems involving soil conservation and reclamation can be avoided.

ERCB pipeline inspectors will also be available for landowners to call, and will see that any complaints are acted upon. They can be reached at the Board's Edmonton Area office (427-0200) or its Bonnyville office (826-5352).

The Board does not agree with Dr. Shirvell's suggestion that a separate appeal procedure be available to landowners in the event that individual concerns are not attended to. The Board believes that it is incumbent upon the applicant to see that proper procedures are followed, and that there are sufficient avenues of communication available to look after problem areas. As mentioned above, complaints should be made to the Board's area offices.

7 CROSSING OF THE GENSTAR LANDS

Figure 2 shows the existing and proposed pipelines across the Genstar lands, as well as the location of Genstar's existing gypsum wallboard plant and planned expansions.

7.1 AEC's Views

AEC proposed a 5-m-wide right of way to the west of and adjacent to existing Shell and AEC rights of way across the Genstar lands, to the point of entrance of an existing 1220-mm inside diameter concrete tunnel. At that point, all of the pipelines enter the tunnel. AEC stated that the proposed 610-mm OD pipeline could not be constructed in its existing 5-m right of way, and noted that the existing pipelines in the corridor had been constructed in adjacent 5-m rights of way, similar to that proposed.

In response to questions from Genstar about routing of the proposed 610-mm OD pipeline to the east of the existing rights of way for that portion of the proposed pipeline across the Genstar lands (see Figure 2), AEC stated that such routing would involve an additional crossing of the corridor pipelines. This would adversely impact on pipeline construction because the direction of construction for that segment of pipeline would have to be reversed. AEC contended that selecting the route to the west of the existing pipelines represented orderly and efficient development in the corridor. AEC also stated that, if and when the construction of a second tunnel across the Genstar lands was required, the appropriate separation distance between the second and the original tunnel would be determined.

AEC stated that it was prepared to enter into an agreement with Genstar respecting possible surface developments over the pipeline tunnel for the proposed pipeline. The agreement would be similar to those it had with Genstar for the existing AEC pipelines.

AEC was confident that it "could obtain an easement (across the Genstar lands) in good bargaining faith", and stated a preference that the Board not require AEC, pursuant to section 11(2) of the Pipeline Act, to obtain an interest in the Genstar lands through negotiation with the landowner.

7.2 Genstar's Views

Genstar contended that construction of the 610-mm OD pipeline to the west of the existing pipelines would adversely affect its plans to expand its gypsum wallboard plant and to construct a gypsum laminating plant. It submitted that "any future westerly rights of way" should be minimized. Accordingly, it proposed an alternative route across its lands to the east of the existing AEC and Shell rights of way, with the necessary crossing of the existing pipelines to be undertaken preferably on adjacent lands. Genstar said the lands to the east of the tunnel had been "sterilized" because of the existing pipelines, and indicated that the effect on its plans would be minimized if its proposed alternative route was chosen.

Genstar submitted a plot plan of the existing and proposed buildings on its lands. When questioned about the merits of routing the 610-mm OD pipeline to the east of the existing right of way, given that its planned laminating plant would extend to the east of the pipeline tunnel, Genstar said the proposed building might be angled to the north so that the proposed 610-mm OD pipeline might be accommodated immediately to the east of the pipeline tunnel. Genstar emphasized that it was mainly concerned about future pipeline tunnels to the west.

Genstar noted that, as a result of the initial AEC pipelines, it had entered into an agreement with AEC respecting expansion of its gypsum facilities over the pipeline tunnel. It was concerned that such an agreement might not be reached for the proposed pipeline and therefore requested that the Board order AEC, pursuant to section 11(2) of the Pipeline Act, to acquire an interest in the Genstar lands by negotiation with Genstar.

7.3 Board's Views

The Board recognizes Genstar's concern about the impact that proposed and future pipelines might have on its expansion plans. However, the Board notes that the proposed pipeline is to be located in the existing pipeline tunnel for which an agreement exists between Genstar and AEC. It further notes that the new 5-m right of way proposed by AEC does not directly encroach on areas that would be included in any of the proposed expansions, and that there is some flexibility regarding the location of the proposed laminating plant. Locating the proposed pipeline to the east of the existing pipelines would require additional pipeline crossings and necessitate the reversal of the direction of construction, both of which would be costly.

For these reasons, the Board accepts AEC's proposed route across the Genstar lands. If the new pipeline and right of way do have an incremental impact on Genstar's ability to expand, the Board expects that this would be a matter for compensation.

The Board is satisfied that the proposed 5-m right of way within the pipeline corridor is appropriate, but takes no position at this time with respect to the location of possible future pipelines or a possible future tunnel. If such facilities are proposed in the future, they would be dealt with on the basis of then existing circumstances.

Regarding Genstar's request that the Board order AEC to acquire an interest in its lands through negotiation with Genstar, the Board notes that AEC said it was prepared to enter into an agreement with Genstar for the proposed pipeline similar to that for its existing pipelines. Further, the Board considers the application of section 11(2) inappropriate in this instance because it does not involve a particularly unique situation where there are public interest reasons for interfering with the normal system for acquiring surface rights. Accordingly, the Board will not require AEC to acquire an interest in the Genstar lands through negotiation.

8 PIPELINE DESIGN, CONSTRUCTION, AND OPERATION

8.1 AEC's Views

AEC based its pipeline design on the Canadian Standards Association standard Z183-M1982[1] Oil Pipeline Transportation Systems, and the Pipeline Act and Regulations.

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[1] Canadian Standards Association, 1982. Oil Pipeline Transportation Systems, Pipeline Systems and Materials. Standard Z183-M1982. Rexdale, Ontario.

For the proposed 406.4- and 610.0-mm OD blended bitumen pipelines, AEC plans to use new CSA Z245.1-M1982[2] Grades 359 and 414 Category 2 and ASTM A333[3] Grade 6 seamless pipe with a maximum operating pressure of 6825 kilopascals (kPa).

For the proposed 219.1-mm OD diluent pipeline from the Ardmore Junction to the CLPP pump station, AEC plans to use new CSA Z245.1-M1982 Grade 290 Category 2 pipe with a maximum operating pressure of 10 200 kPa.

The existing 323.3-mm OD pipeline to be converted from blend bitumen to diluent service comprises CSA Z245.3-M1979[4] Grade 317 Category 2, CSA Z245.5-M1979[5] Grade 359 Category 2, and ASTM A333 Grade 6 seamless pipe with a maximum operating pressure of 10 120 kPa.

AEC said the maximum inlet temperature of the blended bitumen at the CLPP end of the pipeline was about 70°C while the normal inlet temperature would be 55°C. It stated the minimum operating temperature used for design purposes was -5°C and noted that its designs were based on a diluent/bitumen ratio of 32/68.

AEC stated that the locations of block and check valves along the pipeline were selected having regard for the minimum spacing requirements set out in the CSA Z183-M1982, the locations of block and check valves along the existing pipelines, and the potential impacts of computer-estimated spill volumes. It noted that the proposed valves could be remotely actuated by the pipeline operator.

In response to questions by Genstar, AEC agreed that if the proposed pipeline was cased within the pipeline tunnel across the Genstar lands, any future repairs might be easier. It qualified its response, however, stating that the casing of pipelines within tunnels to facilitate repair was practical only for pipelines located at the bottom of the tunnel because the pipelines above would not be affected when the lower pipeline needing repair was withdrawn from its casing. AEC believed that its proposed pipeline could be the last to be located in the tunnel and in any case would be above the existing pipelines. It therefore contended that casing would not be needed. Respecting safety, it said the tunnel in this instance, rather than the casings, provided protection from outside forces. AEC noted that its existing 168.3-mm OD pipeline would not be needed to transport diluent once the 323.9-mm pipeline was converted to diluent service and would be available for alternative uses although one had not yet been identified.

Respecting the effect not casing the 610-mm OD pipeline might have on possible future pipelines (notwithstanding its opinion that the proposed pipeline would be the last in the tunnel), AEC said that if another smaller pipe line (complete with casing) was placed in the tunnel, the subsequent pipeline and casing would have to be removed at the same time as the 610-mm OD pipeline if it needed repairing.

From the CLPP pump station to the Ardmore Junction, AEC proposed a 25-m-wide right of way with the 406.4-mm OD and 219.1-mm OD blended bitumen and diluent pipelines separated by approximately 15 m. This would minimize heating of the diluent by the hot blended bitumen leaving the CLPP pump station. For that portion of the route from the Ardmore Junction to the pipeline corridor in the SE 1/4 31-53-22 W4M, a 6-m separation distance between AEC's existing 323.9- and 168.3-mm OD pipelines and the proposed 610.0-mm OD pipeline would be maintained. AEC said approximately 21 m of working area within its 30-m right of way would be needed for construction. For the remainder of the route the right of way would be 5 m wide with an 11.5-m-wide temporary working space. The pipeline would be separated by 5 m from an adjacent pipeline.

AEC proposed to begin pump station construction on 1 July 1984 and pipeline construction on 1 August 1984 It expected that pipeline construction would be complete by 15 November 1984 and said that the pipeline would be operational by 1 April 1985.

AEC stated that the pipelines in the pipeline corridor would be located and staked, and that its inspector would be present during construction operations. For operations such as backfilling that would require the operation of heavy equipment over operating pipelines, AEC suggested the use of wide-pad equipment or the placement of special padding to broaden the weight distribution. It said that its construction specifications were not yet complete but would specify precautions to be taken to protect adjacent pipelines.

AEC said that a test program for the proposed pipeline was being prepared, and that it would undertake to supply the program to the Board staff prior to the testing of the pipeline.

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[2] Canadian Standards Association, 1982. **Steel Line Pipe, Pipeline Systems and Materials.** Standard Z245.1-M1982. Rexdale, Ontario.

[3] American Society for Testing and Materials, 1982. **Seamless and Welded Steel Pipe for Low-Temperature Service.** ASTM standard A333-82. Philadelphia, Pennsylvania, USA.

[4] Now Z245.1.

[5] Ibid.

Concerning the operation of the pipelines, AEC said that its supervisory control and data aquisition system would be expanded to serve the proposed 610-mm OD pipeline and would permit operation by remote control. A real-time transient model for liquid pipelines would constitute the basis for leak detection and location on the 610-mm OD pipeline. AEC proposed an internal corrosion control program consisting of injection of corrosion inhibitors at pump stations, regular pigging, monitoring for corrosion at pig trap sites, and periodically running an internal electro-magnetic inspection tool through the pipeline. AEC said its corrosion control program was currently being reviewed, and undertook to provide the Board staff with the results of its corrosion program study as it relates to the operation of the proposed pipelines.

8.2 Interveners' Views

Genstar questioned AEC about the safety of placing the proposed 610-mm OD pipeline in the tunnel across its lands without casing. It also questioned the possibility of future pipelines being installed in the tunnel, and the effect the location of those pipelines would have on the need for casing of the 610-mm OD pipeline. It noted that the existing AEC 168.3-mm OD pipeline through the tunnel would not be used.

IRS said that initially it had a safety concern relating to the separation between the proposed AEC pipeline and the existing parallel pipelines but stated that AEC had since satisfied this concern.

8.3 Board's Views

The Board has reviewed the proposed pipeline design, and particularly the concerns respecting the need for casing of the 610-mm OD pipeline in the tunnel on the Genstar lands, and the pipeline separations proposed along the route in terms of construction safety.

In comparing the advantages and disadvantages of placing the proposed 610-mm OD pipeline in the tunnel with or without a casing, the Board recognizes that if the proposed line is not cased, any subsequent pipeline and casing would have to be removed with the 610-mm OD pipeline should it require repair. Nevertheless, the Board believes that the 610-mm OD pipeline can be safely constructed through the tunnel and operated without a casing. While it recognizes the advantages a casing provides should future pipelines be constructed in the tunnel, there was no evidence submitted respecting future installation of other pipelines. Therefore, the Board will not require a casing for the 610-mm OD pipeline at this time.

On the basis of the information submitted, the Board is satisfied that the design of the pipelines and related facilities proposed by AEC meet the requirements of CSA Z183-M1982 and the Pipeline Act and Regulations.

The Board accepts the procedures proposed by AEC to locate and flag existing pipelines prior to construction, as well as its plans to protect existing pipelines from heavy equipment and to have an inspector on site. It is satisfied that the proposed separation distances and construction procedures are adequate.

9 SUMMARY

The Board believes the proposed pipeline facilities will be needed to transport bitumen from the Cold Lake area. The Board considers AEC's route acceptable and is generally satisfied that AEC's proposed construction procedures will minimize environmental and agricultural impacts. Nonetheless, the Board will advise Alberta Environment of its concerns respecting Manatokan Creek, Ross Creek, and the Bellis natural area. Additionally, the Board will require AEC to inform landowners of its schedule and the names of land agents who will be available during construction to discuss landowner concerns.

The Board finds that AEC's proposed pipeline design, and construction and operating procedures satisfy its requirements.

10 DECISION

The Board is prepared to issue the appropriate construction permits and approvals for Applications 840117, 840118, and 840119, as amended, by Alberta Energy Company Ltd.

The pipeline permits for Applications 840118 and 840119 will have the following condition attached:

> The permittee shall, prior to commencement of construction, inform landowners directly affected by pipeline construction of the construction schedule, the names of its land agents, and a contact procedure to be used during construction.

The construction permits will be issued following:

- receipt of the approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act, and

- receipt of the consent of the Minister of the Environment pursuant to regulations for the Restricted Development Areas crossed.

ISSUED at Calgary, Alberta, on 8 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

GJ DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

APPENDIX

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Energy Company Ltd (AEC) J. W. Beames, Q.C.	M. J. Benson B. J. Bradley, P.Eng. G. E. Edey of Canuck Engineering Ltd. J. E. Starratt, P.Eng.
Dome Petroleum Limited (Dome) W. M. Smith	
Esso Resources Canada Limited (Esso) R. C. Pittman	
Genstar Corporation and Genstar Gypsum Limited (Genstar) D. Zalmanowitz	B. A. Korun, P.Eng.
Industrial Realty Services (Strathmore) Limited (IRS) D. Oxford	D. Oxford
Dr. C. S. Shirvell Dr. H. Simmons W. D. Abercrombie	Dr. C. S. Shirvell Dr. H. Simmons J. Crepin, P.Ag. of Norwest Soil Research Ltd.
Alberta Environment (Crown) R. Dyer, P.Ag.	
Energy Resources Conservation Board staff R. J. Allman, P.Eng. H. R. Hansford H. W. Knox, P.Eng. L. D. Martinuzzi, P.Eng.	

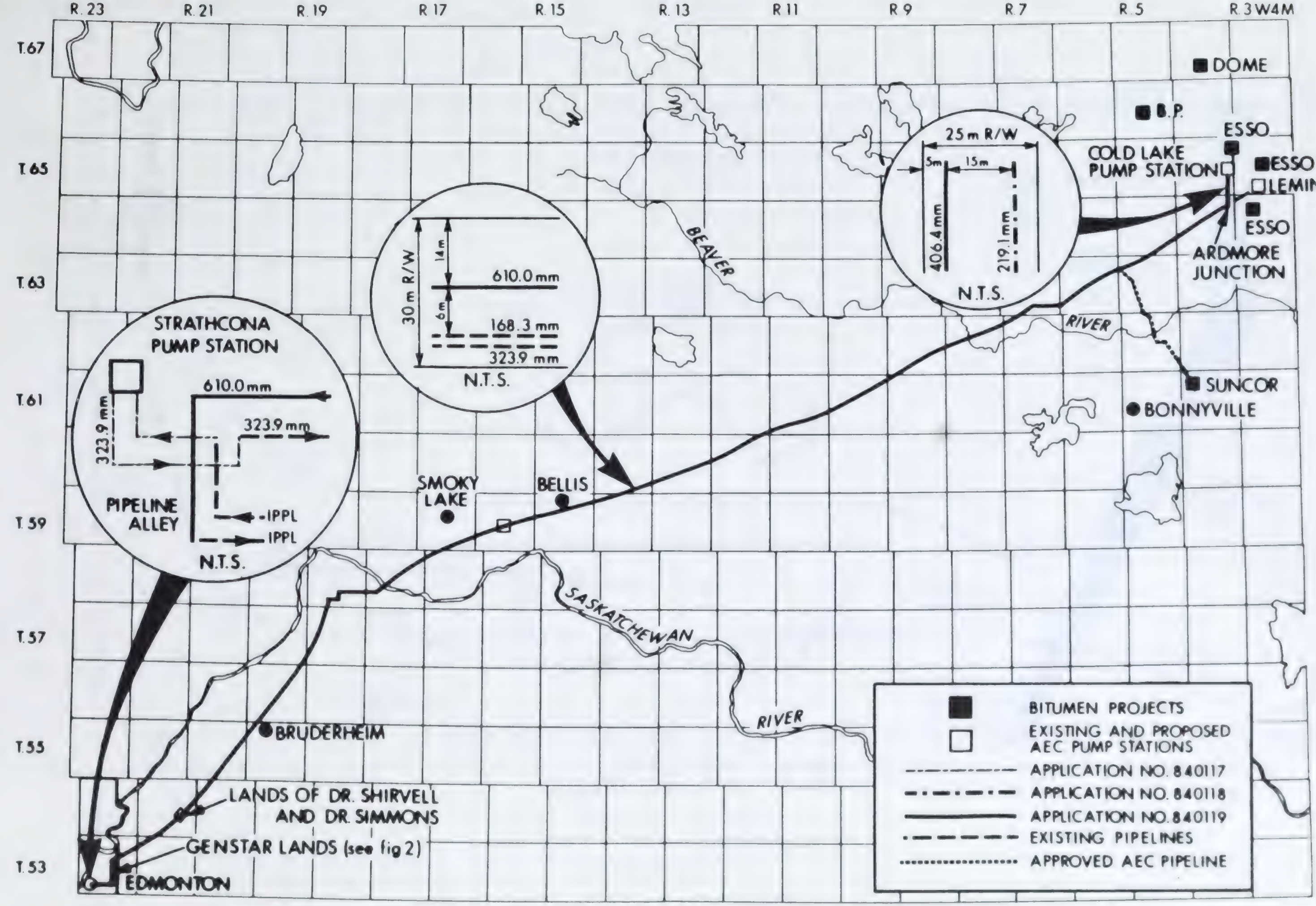

FIGURE 1 ALBERTA ENERGY COMPANY LTD.
EDMONTON – COLD LAKE AREA

D 84 - 10

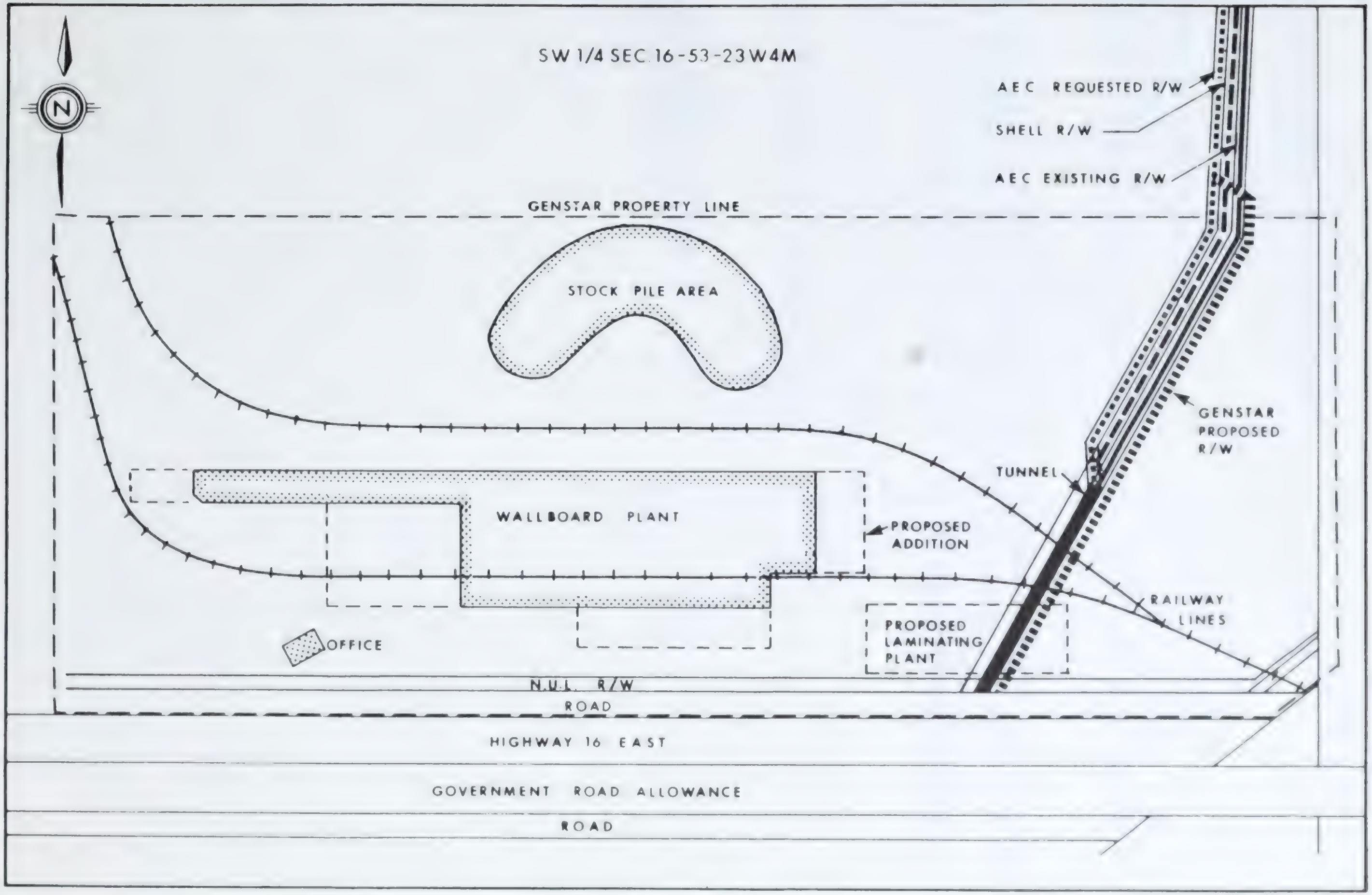

FIGURE 2 GENSTAR LAND DETAIL

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

WESTMIN RESOURCES LIMITED
RATEABLE TAKE
LINDBERGH COLONY W POOL

Decision D 84-11
Application 831118

The Board adopts the examiners' recommendations with the clarification that the order specify that the distribution of gas production in the proportions of 60 and 40 per cent for the 10-1 and 6-6 wells is applicable for production rates above the minimum rates specified in the order.

DATED at Calgary, Alberta, on 23 May 1984.

ENERGY RESOURCES CONSERVATION BOARD

N. Strom
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

WESTMIN RESOURCES LIMITED
RATEABLE TAKE
LINDBERGH COLONY W POOL

Examiners' Report E 84-12
Application 831118

1 INTRODUCTION

1.1 The Application

Westmin Resources Limited applied under section 23(b) of the Oil and Gas Conservation Act (the Act) for a declaration to restrict the amount of gas produced from the Lindbergh Colony W Pool (the W Pool) by distributing the amount of gas that may be produced from the pool in an equitable manner among the wells in the pool.

At the hearing, Westmin Resources Limited requested that the rateable-take declaration be retroactive to 1 September 1983, or alternatively, 23 November 1983.

1.2 The Hearing

The application was considered at a public hearing on 22 February 1984, in Calgary, Alberta, by Board-appointed examiners, H. Antonio, P.Eng., H. R. Keushnig, P.Eng., and B. D. Prasad, P.Eng.

Sulpetro Limited submitted an intervention.

1.3 Background

As shown in the attached figure, the W Pool is a two-well pool containing the wells located in Legal Subdivision (Lsd) 6-6-54-5, west of the 4th meridian (W4M) (the 6-6 well) and Lsd 10-1-54-6 W4M (the 10-1 well).

Sulpetro and Merland Explorations Limited drilled the 6-6 well in December 1981 and tested it in June 1982, obtaining an interpreted absolute open flow potential (AOFP) of 165 thousand cubic metres per day (10^3 m^3/d) from the W Pool. The well began producing in March 1982 and had produced about 34 million (10^6) m^3 of gas to December 1983.

Westmin drilled the 10-1 well in August 1979 and subsequently completed and tested the well in March 1983, obtaining an interpreted AOFP of 471 x 10^3 m^3/d for the W Pool. The well began producing in September 1983 and had produced about 3 x 10^6 m^3 to December 1983.

From the time that both the 6-6 and 10-1 wells have been producing, about 73 per cent of the W Pool's production has been taken from the 6-6 well, and 27 per cent from the 10-1 well.

The Colony gas producible from both wells is contracted to Pan-Alberta Gas Ltd. (Pan-Alberta) under separate sales agreements. Both sales contracts include other wells in the area and allow the seller of gas the option of fulfilling the gas nomination from any of the wells in the contract. Westmin also uses some gas from the 10-1 well as fuel for a steam plant supplying a heavy oil experimental project located in section 13-55-6 W4M, about 11 kilometres (km) from the 10-1 well.

2 ISSUES

The examiners consider the issues to be

- the need for a rateable-take order,
- the basis for distributing production between the 6-6 and 10-1 wells, and
- the effective date of any rateable-take order issued as a result of this application.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Westmin Resources Limited (Westmin) G. L. Thompson, P.Eng.	J. D. Newbert, P.Eng. L. A. Stewart, P.Geol.
Sulpetro Limited (Sulpetro) D. Lane	G. E. Bates, P.Eng. of Bates Log Analysis Ltd. A. Gogol, P.Geol. R. K. Law, P.Eng.
Energy Resources Conservation Board staff K. Fisher, C.E.T. T. K. Wong, P.Geol.	

3 NEED FOR A RATEABLE-TAKE ORDER

3.1 Westmin's Views

Westmin said that pressure measurements taken on the 10-1 well in August 1979 when the well was drilled, and in March 1983 when the well was completed in the W Pool, showed that the reservoir pressure at the well had declined by about 470 kilopascals. The applicant submitted that this decline in pressure had been caused by gas production from the 6-6 well. It argued that drainage would likely continue in future because the sales contract covering the 6-6 well allows that well to be produced at a significantly greater rate than 10-1's contract allows it. Westmin anticipated that, for the contract year commencing 1 November 1983, Sulpetro's 6-6 well would be produced at rates up to about 22 x 10^3 m^3/d, while Westmin's 10-1 well would be limited to only some 6.51 x 10^3 m^3/d, which is 30 per cent of 21.71 x 10^3 m^3/d, the maximum daily rate allowed under its Pan-Alberta contract. Westmin concluded that it would thus not be able to produce its equitable portion of the pool's reserves.

Westmin indicated that it also uses some gas produced from the 10-1 well as fuel for a heavy oil steam flood but the amount of gas required is erratic, and dependant upon the weather and the number of steam generators in use at any time. The applicant said that, in any case, it would be more economical to supply fuel gas for its steam projects from nearby wells than to obtain it on a regular basis from the 10-1 well which is some 11 km from the project. Westmin concluded that it could not count on its fuel gas requirements as a means of allowing it to produce an equitable share of gas produced from the W Pool.

The applicant said that it had been unsuccessful in its attempts to increase the amount of gas to be taken under its current Lindbergh Pan-Alberta contract, or to transfer one of its inactive sales contracts for the Dapp area to the Lindbergh area. Further, it was unable to negotiate a satisfactory voluntary agreement with Sulpetro for equitable withdrawals from the two wells in the W Pool.

Westmin concluded that it is unlikely that the amount of gas it will be able to produce from the 10-1 well will increase in future, and therefore a rateable-take order is required for the W Pool.

3.2 Sulpetro's Views

Sulpetro did not comment directly on whether or not there is a need for a rateable-take order. It agreed, however, that the reserves underlying section 1-54-6 W4M are being drained, and it submitted that it had negotiated diligently with Westmin for a mutually satisfactory solution to the drainage problem.

3.3 Examiners' Views

The examiners agree that the W Pool reserves associated with the 10-1 well are being inequitably drained by production from the 6-6 well, and will likely continue to be inequitably drained in future, because the sales contract associated with the 6-6 well allows the well to produce substantially more gas than can be produced under the contract associated with the 10-1 well. Further, the examiners are satisfied that Westmin has made reasonable attempts to negotiate an arrangement to solve the drainage problem. Therefore, the examiners conclude that a rateable-take order is required to provide for equitable withdrawals of gas from the 6-6 and 10-1 wells.

4 BASIS FOR DISTRIBUTING PRODUCTION

4.1 Westmin's Views

Westmin requested that the production from the W Pool be distributed between the 6-6 and 10-1 wells in proportion to the reserves associated with each well. It proposed that the proportions be calculated using wellbore reserves parameters (net gas pay, porosity, and water saturation) as determined from all available log data and assuming equal areas for each well, rather than on the basis of an isopach map, because mapping the pool is quite interpretive. The applicant submitted wellbore parameters for the two wells and calculated that 61.8 per cent of the W Pool's reserves are associated with the 10-1 well, and 38.2 per cent with the 6-6 well (see attached table). At the hearing, Westmin revised its recommendation to 71.8 per cent for the 10-1 well and 28.2 per cent for the 6-6 well on the basis of additional material submitted during the hearing. It concluded that the total production from the pool should accordingly be taken from each well in the latter proportion, with production balancing being done on an annual basis, until either well is not capable of producing against existing pipeline pressure.

With respect to the wellbore parameters, Westmin noted that the sonic and neutron-density logs show similar intervals of gas effects in the 10-1 well; however, in the 6-6 well, the sonic log does not show a classic gas effect in a lower Colony interval as does the neutron-density log. It concluded that the net gas pay for the well is less than indicated on the neutron-density log, as shown in the attached table. With respect to water saturation calculations, the applicant indicated that it had used a water resistivity of 0.1 ohm-metres, which it obtained from a Canadian Well Logging Society publication.

In response to Sulpetro's request that any rateable-take order establishing the proportion of the W Pool production to be taken from each well include a condition that Westmin's Pan-Alberta contract requirements be satisfied from production from the 10-1 well, Westmin indicated that it intended to produce the 10-1 well as much as possible. It said that it would agree to produce its Pan-Alberta contract requirement preferentially from the

10-1 well, provided that it could produce the requirement from other wells included in the contract if any problems developed which resulted in the 10-1 being shut in, and provided that Sulpetro also produced its contract requirements preferentially from the 6-6 well to the limits set out by a rateable-take order.

The applicant disagreed with Sulpetro's proposal that an annual allowable gas production volume be established for each well and that these allowable volumes be based on well capacity as well as on reserves. Westmin did not see how the allowables could be set in view of the uncertainty in the rates of production to be nominated by Pan-Alberta. Further, the applicant questioned the validity of Sulpetro's suggestion that well capacity could be defined as the average production over the last three months, plus Westmin's fuel gas requirement in the case of the 10-1 well. The applicant said that this was an indication of the deliverability available under current conditions and was not a reflection of the capability of the wells. The applicant noted that the current estimates of the AOFP of the wells had been determined at different periods in the pool's history, and that there was some question as to the validity of the AOFP calculated for the 10-1 well. Therefore, if well capability, as indicated by AOFP tests, were to be used in a formula to set allowable production volumes, both wells should be retested so that they would be on an equal footing. The applicant also said that in any case its fuel gas needs could not be considered in setting an allowable production volume for the 10-1 well because the requirement is erratic and is likely to be produced from other wells in the future.

4.2 Sulpetro's Views

In its intervention, Sulpetro proposed that production from the W Pool be distributed in proportion to the reserves underlying the drilling spacing unit of each well, as determined on the basis of its net gas pay isopach map. It expressed a high degree of confidence in its mapping, indicating that it had taken into account the regional geological trends in addition to all possible well data. On this basis, Sulpetro calculated that 57.2 per cent of the reserves of interest are associated with the 6-6 well, and 42.8 per cent with the 10-1 well.

Sulpetro also submitted values for the wellbore parameters it had determined for the two wells (see attached table), some of which differed from those submitted by Westmin. It was of the opinion that the neutron-density log is a superior tool for the recognition of gas, while the sonic log is unreliable for the purpose. It argued that even though the gas effect in the lower Colony interval in the 6-6 well on the neutron-density log is less than in the upper intervals, the effect is nevertheless due to the presence of gas, and therefore the lower intervals should be included in determining net pay. With respect to calculating water saturations, Sulpetro preferred to use a water resistivity derived from the data on the wells involved; thus, it averaged the values determined for the two wells, obtaining a water resistivity of 0.17 ohm-metres. On the basis of wellbore parameters, Sulpetro calculated that 44.01 per cent of the reserves involved underlie section 6-54-5 W4M and 55.99 per cent underlie section 1-54-6 W4M.

Sulpetro submitted that any rateable-take order issued setting the proportions of production to be taken from each well in the W Pool should specify that all of Westmin's Pan-Alberta contract requirements be produced from the 10-1 well, and that the order expire on the date that is the earlier of either well becoming incapable of production, the effective date of the unitization of the W Pool, or termination of either party's gas contract. Sulpetro further indicated that no discussions had taken place on unitization of the W Pool to date.

At the hearing, Sulpetro modified its proposals for a rateable-take order for the W Pool. It preferred that an annual allowable production volume be set for each well. It submitted that, considering the interpretive nature of both mapping the pool and determining wellbore parameters, the allowable production be based 50 per cent on the reserves underlying the drilling spacing unit of each well, and 50 per cent on well capacity. Sulpetro proposed that the reserves portion of the rateable-take formula be based on its isopach map, and that the well capacity portion be taken as the average production over the last three months for each well, including Westmin's fuel gas requirements for the 10-1 well. It argued that the current estimates of the AOFP of the wells should not be used as a measure of well capacity because the AOFP of the 10-1 well was inconclusive, with the sandface AOFP of 471 x 10^3 m^3/d being unusually higher than the wellhead AOFP of 96 x 10^3 m^3/d.

Sulpetro contended that setting a maximum annual allowable production volume for each well would be desirable because it would permit each party to produce its well even if the other well were shut in for any reason. Further, the intervener said that annual allowable production volumes would take into consideration monthly variations in demand (Sulpetro intends to continue to produce the 6-6 well to meet peak demands in winter) and would eliminate the need for the conditions it had requested be included in any rateable-take order. Sulpetro also argued that allowable production volumes for the W Pool wells would not be a problem even if market demand increased, because the wells' productivity would have decreased so that the demand could not be met in any case.

Finally, regarding possible alternative methods of setting allowable production volumes, Sulpetro said that applying the industry's nominal rate of take of 1/7300 (daily production/reserves) would result in uneconomic rates for both wells.

4.3 Examiners' Views

The examiners believe that the production from the W Pool should be distributed between the 6-6 and 10-1 wells in proportion to the reserves underlying the drilling spacing units of the wells. They agree with Westmin that the reserves should be calculated on the basis of wellbore parameters, assuming equal areas for each well. In their opinion, there is insufficient data to map the pool as accurately as would be desirable if the reserves in a rateable-take formula were to be based on a net pay isopach map. In addition, the examiners believe that it would be inappropriate in this case to use well capacity for distributing production from the pool. In this regard, they agree with Westmin that Sulpetro's formula for estimating well capacity is an indication of the deliverability possible under current sales contracts, and cannot be considered a measure of well capability. Further, the examiners agree with both Westmin and Sulpetro that current estimates of well capacity, as measured by the AOFP, should not be used in a rateable-take formula because the data for each well were obtained at different periods in the pool's history and the data for the 10-1 well appear questionable. Because of the additional costs involved, the examiners would be reluctant to request further testing of the wells, and they conclude that distributing production on the basis of reserves is the most practical approach.

The examiners have reviewed the wellbore parameters and have adopted the values shown on the attached table, considering the arguments presented at the hearing regarding sonic and neutron-density logs. They agree with Sulpetro that the sonic log is not always reliable. The examiners are of the opinion that when the two log types are in disagreement, the neutron-density log should be used because it can indicate effective porosity after gas effect corrections, whereas there is no provision for gas effect correction for the sonic log. With respect to obtaining a water resistivity value to use in calculating water saturations, the examiners again concur with Sulpetro that it would be appropriate to use data obtained from the wells involved in the application. Accordingly, the examiners used a water resistivity of 0.16 ohm-metres calculated from log data for the two wells. On the basis of the above, the examiners conclude that an equitable distribution of the W Pool's production would be 60 per cent from the 10-1 well and 40 per cent from the 6-6 well.

The examiners considered how the proportion would be practically applied, and whether any additional conditions need to be stipulated. Both the applicant and intervener were concerned that one well's production could be unilaterally reduced or stopped for any reason, and hence the other would be required to do likewise. The examiners are reluctant to impose a requirement, as discussed at the hearing, that market nominations under the two respective gas sales contracts be taken preferentially from the W Pool. To do so would be to explicitly require that production from other wells in the respective contracts be restricted, which may lead to inequities to the owners of these other wells. The examiners believe that there may be merit in the applicant and intervener reaching a private agreement of this kind, but that it is not proper for the Board to impose it.

Regarding Sulpetro's proposal of a maximum rate (or allowable) for each well, the examiners conclude that rates set now would not likely remain appropriate very far in the future because of changing market conditions.

The examiners note that section 23(b) of the Act, concerning rateable take, requires that "each well owner... be given...the opportunity of producing or receiving his share of the gas in the pool". The examiners believe that "opportunity" means the earliest opportunity, and that one owner should not, where he has discretion to do otherwise, prevent another from producing. A minimum guaranteed rate for each well would serve to guard against this. Specifically, a minimum rate would

- avoid the above-mentioned problems of one well, for possibly unjustifiable reasons, forcing the other well to be shut in,
- allow more reliable production planning, and
- maintain some incentive for well owners to look for new markets if existing ones deteriorate or terminate.

Under this approach, permanent minimums would be set for each well which would allow one operator to produce up to this level even if the other operator had to shut in its well for any reason. However, Pan-Alberta would not be obligated to purchase this minimum quantity of gas. For any production rates above these levels, the established proportions would have to be maintained. The examiners believe that a suitable minimum for the 10-1 well would be the quantity anticipated to be taken in the 1983-1984 contract year under Westmin's contract with Pan-Alberta, as reported by Westmin (see Section 3.1 of the report). This would be 6.51×10^3 m^3/d or 2377×10^3 m^3/year. The corresponding minimum for the 6-6 well of 4.34×10^3 m^3/d or 1586×10^3 m^3/year would be obtained by multiplying the minimum rate for the 10-1 well by a ratio of 40/60, the proportion in which the examiners recommend the pool production be split between the two wells.

All production balancing would be done on an annual calendar-year basis, with the proportions of gas to be taken from each well in accordance with the examiners' recommendations from the effective date of the rateable-take order. Proportioning of production would therefore be in effect for only a part of 1984. The minimum producible amount for the remaining portion of 1984 would be calculated by multiplying the daily minimum rate for each well noted above by the number of days remaining in 1984. In 1985, the minimum yearly rates calculated above would prevail. No maximum rate limits would be applied.

The examiners believe that they should not attempt to specify the various possible circumstances under which the order would terminate, but rather to leave it to parties subject to the order to apply for any change that may appear necessary.

5 EFFECTIVE DATE OF THE ORDER

5.1 Westmin's Views

Westmin requested that, in view of the severe drainage that has occurred from its property, the effective date of the rateable-take order be made retroactive to 1 September 1983, the date the 10-1 well was tied in, or alternatively, to 23 November 1983, the date of the application.

5.2 Sulpetro's Views

Sulpetro requested that any rateable-take order issued be made effective on the date that the order is issued. It argued that, in any event, the Board has jurisdiction under the Act to make the order retroactive to the date of the application, 23 November 1983, and not previous to that date.

5.3 Examiners' Views

The examiners note that section 45 of the Act, to which reference was made at the hearing, allows the Board to specify the effective date of an order issued under Part 10 of the Act to be earlier than the date the order is issued, but not previous to the date on which the application for the order was made. However, section 23 of the Act, under which this application was made, is included under Part 7 of the Act, which has no provision for retroactivity. The examiners therefore conclude that the rateable-take order should be effective on the date that it is issued.

6 RECOMMENDATION

The examiners recommend that

- the Board issue an order distributing gas production from the Lindbergh Colony W Pool between the 10-1 and 6-6 wells in the proportions of 60 and 40 per cent, respectively,
- minimum rates of 2377 x 10^3 m^3/year and 1586 x 10^3 m^3/year be permitted for the 10-1 and 6-6 wells, respectively, and
- the order become effective on the date that it is issued.

DATED at Calgary, Alberta, on 17 May 1984.

HAntonio

H. Antonio, P.Eng.

HR Keushnig

H. R. Keushnig, P.Eng.

BD Prasad

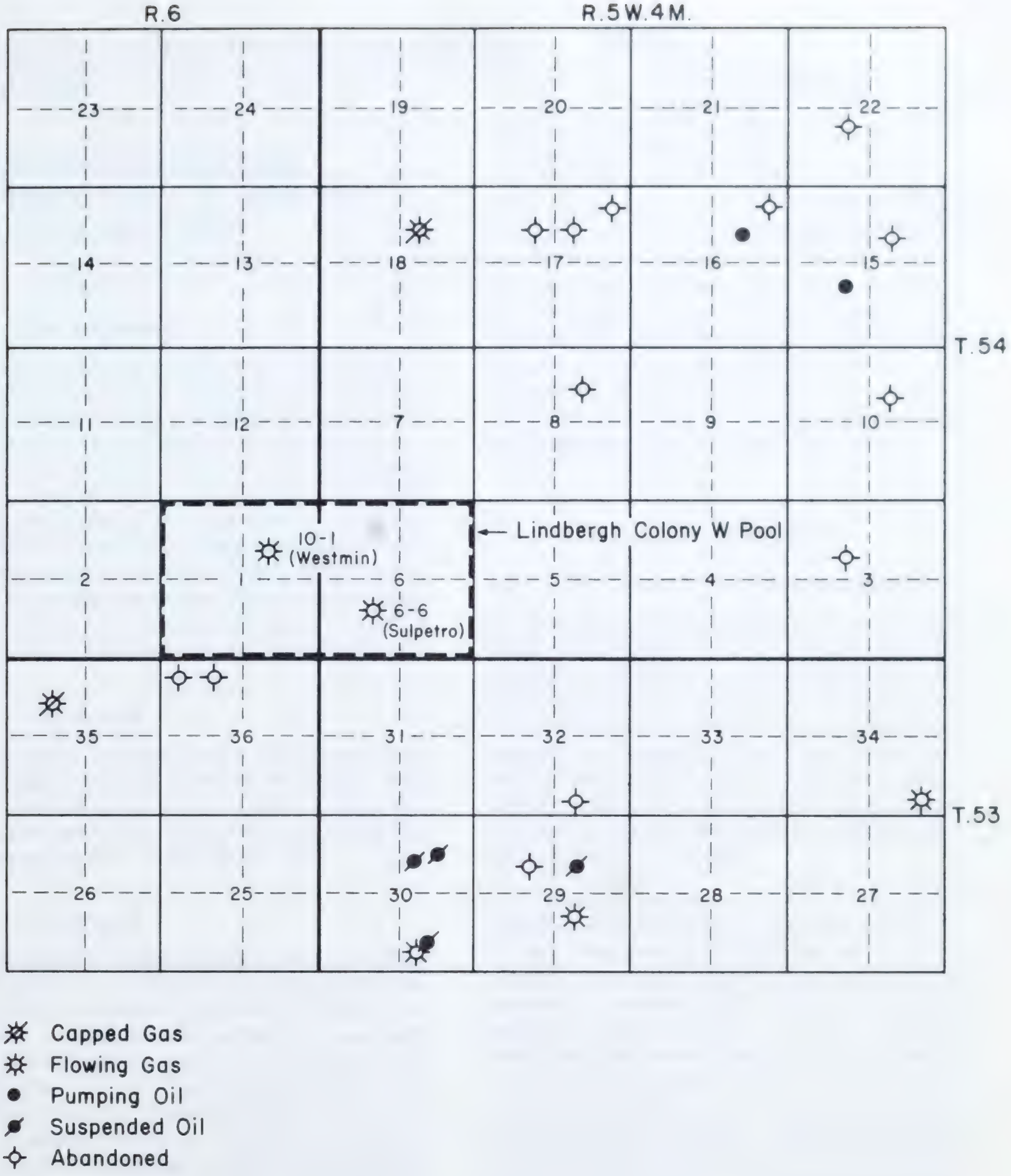
B. D. Prasad, P.Eng.

WELLBORE RESERVES PARAMETERS
SULPETRO MERLAND LINDBERGH 6-6-54-5 AND BRASCAN LANDON 10-1-54-6

	6-6 Well				10-1 Well			
	Westmin		Sulpetro	Examiners	Westmin		Sulpetro	Examiners
	Density Log	Sonic Log			Density Log	Sonic Log		
Net Pay (metres)	4.5	2.25	4.8	4.0	7.0	7.0	7.0	6.0
Porosity (fraction)	0.24	0.275	0.29	0.28	0.255	0.244	0.27	0.28
Water Saturation (fraction)	0.20	0.183	0.19	0.22	0.22	0.248	0.24	0.22
Proportion of Pool Production (per cent, as calculated using formula given below)	38.2	28.2	44.0	40.0	61.8	71.8	56.0	60.0

Proportion of Production for well

$$= \frac{\text{Net Pay x Porosity fraction x (1-Water Saturation fraction) for well}}{\text{Sum of (Net Pay x Porosity fraction x (1-Water Saturation fraction)) for both wells}} \text{ x } 100$$



LINDBERGH COLONY W POOL
APPLICATION NO. 831118

2.2 Public Interest Effects

The applicant stated that he was prepared to absorb the capital cost of approximately $90 000 for the wind-powered generator. He submitted that he should in turn receive fair value for the surplus energy delivered to TransAlta. He contended that interconnection of his installation would defer construction of new generating facilities on the Alberta interconnected electric system (AIS), even though only by a small amount compared to the size of the generating units presently being added to the AIS. During periods of surplus energy sales to TransAlta, there would be savings in fuel, operating, and other associated costs to the utilities. Because the wind-powered generator is located close to other distribution loads, transmission and distribution losses would be reduced. Therefore, customers of the AIS would benefit from his installation and, since he has paid the full capital cost for the generator, no one else would be adversely affected.

The applicant stated that, because wind energy is a renewable resource and pollution free, wind-power installations should be encouraged in southern Alberta where there is a high wind regime, particularly in the winter chinook months when the system power demand is also highest. The applicant also expressed the opinion that wind-powered generators should be installed on the basis of their own economic merits, and the price paid for surplus wind energy should not be subsidized by customers of the AIS.

2.3 Sale of Surplus Energy

The applicant stated that, in the first few years, his wind-powered generator would generate more energy annually than his operations required. TransAlta has agreed to interconnect the generator and has offered to purchase any surplus energy generated. TransAlta's offer is based on installing two separate uni-directional meters for the interconnection, one to measure flow to Mr. Sinnott's operation and to be charged at normal utility rates, the other to measure surplus energy flow to TransAlta's system that would be paid for at the price of 1.6¢/kWh, but subject to any further order of the Public Utilities Board. The applicant argued that TransAlta's proposal to purchase surplus energy is unfair because it does not recognize the contribution made by the generator to reduce the need for new capacity on the AIS, and the rate of 1.6¢/kWh offered for his surplus energy is far below its true value.

The applicant proposed two options for the exchange of electricity between him and TransAlta. The first option, which he referred to as "net energy billing", is a sharing of energy and capacity, recognizing the economics to both parties involved. The net excess electric capacity and energy at the end of a billing period would be delivered free of charge to TransAlta who would resell it elsewhere at full retail value. In return, TransAlta would supply any shortfall in his energy requirements during periods of low or no wind generation. In this arrangement, energy would be measured by allowing the standard meter to run in reverse when surplus energy is being produced. The net energy supplied by TransAlta would be charged at normal utility rates.

The second option suggested was the 'surplus energy purchase' option under which all the energy supplied by TransAlta would be metered and billed at normal utility rates. The energy supplied by the applicant to TransAlta would be metered separately and paid for at a rate equivalent to the highest-cost energy produced on the TransAlta system. This option assumes that the most expensive energy produced by TransAlta (or AIS) would be cut back first during periods when the wind-powered generator is producing excess energy. Determination of highest-cost energy would take into account the displacement fuel and long-term avoided costs associated with that generation. This would require installation of two uni-directional meters wired in series.

2.4 Other Terms and Conditions

The applicant claimed that interconnection and metering costs should be shared between TransAlta and himself, since the wind plant provides some benefits to the customers of TransAlta. Mr. Sinnott was also concerned that the level of third-party insurance that TransAlta insisted he carry is excessive, given the risk associated with the interconnection.

3 INTERVENERS' SUBMISSIONS

D. M. Cousins supported the application. Using Pincher Creek wind data, he calculated a slightly lower average annual output of 112 500 kWh for the wind-powered generator. He stated that at the time of year when the demand on the AIS is at its highest level, the power available from the wind is also at its highest level. Because of the very nature of the wind, the AIS must react very quickly to compensate for fluctuating production from the generators. In his opinion, this reaction would likely be a reduction in water flow to a hydro-generating unit, resulting in storage of that water in the reservoir for use at a later time. Mr. Cousins also stated that the small power producer (SPP) should not be subsidized by the utility or its customers, but sufficient wind-powered generators should be built so that they could be studied and more data gathered about their operation.

R. M. Bennett was in favour of the application. He stated that a higher rate should be paid for sales of any surplus energy and that the net energy billing option should be available to an SPP. Mr. Bennett also argued that TransAlta's requirement for the applicant to carry $2 million of third-party liability insurance was excessive. He noted that farm customers who operate standby generators in conjunction with their normal supply from the AIS are not required to carry insurance even though they pose similar risks as the Sinnott installation.

W. Arsene supported the application on the basis that there are employment and economic benefits associated with the wind-energy industry. He favoured a trial period to gain more information regarding wind-powered generator operation and associated costs.

J. Edworthy of Nor'wester Energy Systems Ltd. (Nor'wester Energy) estimated the annual energy production from the wind-powered generator would be about 115 000 kWh. He outlined several benefits of wind power, such as deferment of capital expenditures by the utilities, increased reliability of the system due to generation dispersion, economic benefits, job opportunities, energy diversity, conservation of fossil resources, and protection of the environment. He was of the opinion that the applicant should bear the interconnection and metering costs. He argued that rates set for sale of excess energy to TransAlta should include consideration for avoided line losses (because generation is located near the load), generating capacity credit, avoided fuel costs, and some recognition of the costs of the generation by the SPP. He agreed that the utility and the SPP should not subsidize each other.

Considering that limited information is available on the effects of wind power in Alberta, Mr. Edworthy recommended that the Board adopt an interim policy for the next three years to encourage development of wind power to a maximum total capacity of 100 megawatts. After that time, all relevant issues and policies should be reviewed based on local practical operating experience. He further recommended that, in conjunction with this interim period, a joint committee be established of utility, government, wind-energy industry, and citizen members to monitor wind-powered generator and utility interactions, performance, and concerns raised by the issues discussed at the hearing. This committee would be charged with arriving at recommendations regarding allocation of costs, liability, and other concerns based on operating experience in Alberta and reporting these recommendations to the Board for policy revisions.

Alberta Power Limited (Alberta Power) stated that utility interconnections with customer-owned generation should be encouraged to promote the efficient use of energy resources and the innovative and economic development of conventional and alternative electric energy sources. It argued that all consumers of electricity should benefit from customer-owned generation interconnected with a utility's system. Also, customer-owned generation should be considered as a customer class of negative load with credits for demand (capacity) and energy based on the reduction of system co-incident peak load and savings in energy generation. Alberta Power suggested that surplus energy from an SPP be bought at a fixed rate which would be somewhat less than what Alberta Power sells its energy for, but one which would make some allowance for capacity credit.

TransAlta supported the principle of customer-owned generation and took the position that any customer may interconnect and operate electrical generation in parallel with TransAlta's system. In order to be fair to the rest of its customers, TransAlta said it is prepared to purchase all of Mr. Sinnott's surplus energy at a price equivalent to avoided AIS energy cost.

TransAlta submitted that it would be more appropriate to use wind data gathered at the Pincher Creek station to compute average annual energy production from Mr. Sinnott's generator, and it estimated this would amount to about 100 000 kWh.

TransAlta noted that the wind-powered generator must be interconnected with an external source of power in order to start and operate it, and that it would shut down if there is a loss of power from the external source. It also noted that the output from the proposed generator is primarily dedicated to supply the applicant's own requirements. Energy would not be available to TransAlta unless it is not required by Mr. Sinnott's own operations. As there is no assurance of supply of any amount to TransAlta at any given time, there could be no capacity costs avoided by TransAlta. Therefore, the value of Mr. Sinnott's surplus energy to TransAlta lies in displacement of AIS energy only, and in a small reduction in transmission losses. In calculating the value of Mr. Sinnott's surplus energy, TransAlta estimated that the generator energy production would be distributed equally over the year, and the net fuel savings would consist of 50 per cent gas and 50 per cent coal. Allowing an additional 5 per cent credit for savings in line losses at the transmission level, TransAlta determined that 1.6¢/kWh would be appropriate for the avoided energy cost. Allowance for savings in line losses at the distribution level should not be included because any potential savings are offset by the need to distribute the surplus energy purchased over the distribution system. TransAlta stated that, if the applicant is prepared to dedicate his capacity to the system, there may well then be some credit for capacity.

TransAlta stated that interconnection and metering costs should be entirely absorbed by the applicant unless the benefits of the wind-powered generator are also shared. TransAlta said it would install, at its own cost, a time-of-day meter on an experimental basis at Mr. Sinnott's facility to assess the capacity the generator can actually provide each hour of the day, and to monitor the characteristics of the generator.

4 BOARD'S VIEWS

This report deals with the specific issues of the application. The applicant also submitted a significant amount of information and related material regarding wind-power production in other jurisdictions. Much of this material is not discussed in this report and may not be applicable to Alberta, but might provide useful information to interested persons.

Since the present application may be the first of many similar applications by SPPs, the Board has dealt specifically with the application in the body of this report and then expanded upon its views, or dealt with other matters, in the appendix. Although each future application would be decided upon its particular merits and facts, some general principles applied by the Board in dealing with this application are discussed in the appendix.

The Board observes that the proposed wind-powered generator is equipped with voltage and frequency protection relays and notes that it meets TransAlta's requirements for parallel operation with the utility system. Furthermore, Mr. Sinnott stated that the generator would comply with standards as set out by the Canadian Standards Association and the Electrical Protection Branch. The safety of linemen working on a line connected to an SPP facility is a valid concern, and the SPP operator must take sufficient precautions. In this respect, the Board is satisfied that Mr. Sinnott and TransAlta will install the necessary equipment required to prevent unsafe occurrences.

A range of estimates of the output of the Sinnott installation was presented and discussed, and the Board believes it would probably be more accurate to use the wind data from the closest meteorological station to the wind-powered generator to compute the annual energy production and the likely economic benefit of the facility to him. In this instance, the differences are small and the overall analysis pertinent to the decision is not materially affected.

On the relationship and effect of Mr. Sinnott's generator on the TransAlta and Alberta systems, as discussed more fully in the appendix, the Board believes that while the effects may be real the impact of a single SPP cannot, at this time, be accurately determined. The relationship and effect of SPPs on the AIS will depend upon the development of SPPs and will require analysis of their operating experience. To this end, the Board believes a concerted effort should be made to obtain credible technical information on the operation and interaction of the generator with TransAlta's system.

The Board does acknowledge some of the potential benefits of SPPs as presented by the Sinnott application. The Board also believes that a desirable environment for the development of SPPs should be encouraged and, in its opinion, a period of experience to gather information on the performance of SPPs is necessary to reconcile their true impact on the AIS.

The Board notes that the wind-powered generator would be used to meet Mr. Sinnott's own requirement first, and only surplus energy would be made available to TransAlta. Furthermore, Mr. Sinnott needs an interconnection with the distribution system of TransAlta for generator induction power, back-up supply, and to feed surplus energy back to the utility. So in a sense, Mr. Sinnott would continue to be a customer and a load to TransAlta and would be billed at the same rate as other customers with similar loads. To the extent that Mr. Sinnott reduces his own load, the Board believes that this will, on average, reduce TransAlta's generation and tend to delay new generation capacity requirements, even though by a very minute amount. Therefore, TransAlta will see an actual reduction in energy generated since Mr. Sinnott will take less energy from TransAlta than he would have as a pure load, ie with no generator. For these very general and simplistic reasons, the Board believes that, for a trial or learning period, very simple cost procedures should be used for arriving at the value of surplus energy from the applicant's plant. Also, the applicant should then be content to receive some but not all of the perceived, and yet unproven, benefits of his generator.

The Board believes that Mr. Sinnott's operation should be treated as that of a customer who, by managing his load to conserve energy, will reduce his requirements from TransAlta. Furthermore, Mr. Sinnott should be compensated for the surplus energy that he generates by being allowed to "bank" it in TransAlta's system during periods when his generation exceeds his load. Mr. Sinnott would then be able to use his "banked" energy during periods of low or zero generation by drawing energy from the TransAlta system. Although this is similar to the net energy billing concept suggested by the applicant, the Board believes that, during the learning period, two meters should be installed. One meter would record all the energy production from the wind-powered generator and the other would record Mr. Sinnott's consumption, and the difference in the two meter readings would be used to compute the billing. The Board would suggest that the banking and the billing period should be identical and that a quarterly billing period would appear suitable. If during each such period TransAlta is a net supplier of energy to the applicant, then he would be billed for this energy at the usual utility rates, but if the applicant produces more energy than his own requirement during the same period, then TransAlta would compensate him for such surplus energy at a suitable surplus energy rate.

The Board believes there is some definite but unquantifiable capacity contribution made by Mr. Sinnott's wind-powered generator, and that this would be compensated for by the reduction in energy cost to Mr. Sinnott by the modified net energy billing concept which would allow him to bank excess energy in TransAlta's system for his later use.

The Board believes that any cost to TransAlta of foregoing the charge for the energy Mr. Sinnott produces for himself is a reasonable cost for the trial period with this form of energy production. However, TransAlta should recover the cost of kilowatt demand capacity required by the applicant's operation and provided by TransAlta, just as it would for any other load with a similar service. If the present rate structure does not adequately cover the cost of providing required kilowatt demand capacity, an appeal could be made to the Public Utilities Board to set an appropriate rate.

Respecting the value of surplus energy, TransAlta computed an avoided energy cost derived on the basis of displacement of 50 per cent gas-fired energy and 50 per cent coal-fired energy, plus 5 per cent credit for avoiding line losses at the transmission level. The Board believes that during the trial period this is a fair method for computing costs avoided by TransAlta as a result of net surplus energy delivered to it from the interconnection with the applicant's facilities. The Board believes this interim arrangement would be fair to both parties and would be without substantial subsidy. However, this should be reviewed and adjusted as the cost of service is revised by the Public Utilities Board from time to time.

As stated earlier, the Board believes there should be a trial or learning period to determine the true impact of the Sinnott installation. During this period, TransAlta should, with the co-operation of the applicant, obtain all relevant technical and cost information on the operation and interaction of the Sinnott wind-powered generator with the TransAlta system, and submit to the Board a report on this matter for each calendar year and a final summary report before the end of the trial period. Should the Electric Utility Planning Council choose to submit a report or describe an industry position, the Board would welcome it. This trial or learning period should be for five years ending 31 December 1989.

The Board believes that all costs incurred by TransAlta that are beyond those required to connect and meter a customer of similar service size and class, should be paid for by the applicant. The costs of special test metering during the trial period should be borne by TransAlta, and the Board was encouraged to hear TransAlta's plans to install a time-of-day meter, at its own cost, for experimental purposes. In addition, all costs incurred by the applicant to allow for the safe and reliable operation of its generation in parallel with TransAlta's system should be borne by the applicant. If further interpretation is required, the Board observes that all parties agreed that neither an SPP nor a utility should subsidize each other.

The Board assumes that TransAlta would treat customers with standby generation, or with a generator such as Mr. Sinnott's, equally; however, the Board considers matters such as liability or insurance to be part of normal business arrangements and should be resolved by negotiation between Mr. Sinnott and TransAlta.

5 DECISION

Having considered the evidence, the Board believes that the construction, operation, and interconnection of the Sinnott wind-powered generating facility is in the public interest and consistent with the requirements of the Hydro and Electric Energy Act.

The Board is prepared to issue a final approval for the operation of the wind-powered generator, and an order to allow the continued inter-connection of the wind-powered generator to the distribution system of TransAlta Utilities Corporation.

DATED at Calgary, Alberta, on 8 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

R. G. Paterson

R. G. Paterson, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
A. E. Sinnott G. Jasman	A. E. Sinnott D. Gilmer of Enertech Corporation J. Otis of Wind Dynamics D. Johnson of Wind Dynamics
TransAlta Utilities Corporation (TransAlta) M. H. Patterson, Q.C. E. J. McCoy	G. D. Lyons, P.Eng. M. J. Chorel, P.Eng.
Alberta Power Limited (Alberta Power) K. F. Miller	C. O. Twa, P.Eng. B. Laing, P.Eng. R. V. Baer, P.Eng.
Nor'wester Energy Systems Ltd. (Nor'wester Energy) J. Edworthy	J. Edworthy
R. M. Bennett	R. M. Bennett
W. Arsene	W. Arsene
D. M. Cousins, P.Eng.	D. M. Cousins, P.Eng.
Energy Resources Conservation Board staff M. J. Bruni A. Kwaczek F. Rahnama J.N.G. Yu, P.Eng. S. S. Lota, P.Eng.	

APPENDIX
TO DECISION D 84-12 ON THE SINNOT WIND-POWERED GENERATOR

Given the growing interest in small power production and co-generation in Alberta, the Board believes it is appropriate to expand and illustrate its views developed in reaching a decision on the Sinnot application for approval of the operation of a wind-powered generator connected to the Alberta interconnected electric system (AIS). Following this first hearing dealing with the interconnection of a small power production facility and the AIS, the Board concluded that, while the potential benefits and impacts of small power production could be described, the lack of operating experience precluded an adequate assessment of these factors. Considering the interest in the Sinnott application, the Board anticipates this may well be the first of many similar applications.

For purposes of this report, the Board defines a small power producer (SPP) as a connected utility customer that supplies some or all of its own electric load from its own on-site generation of 100 kilowatts or less of total installed name-plate capacity. This is distinct from co-generation, which usually involves the generation of electricity with thermal energy required for some other purpose. Such co-generation is often associated with large industrial projects and is negotiated as part of a supply contract with the appropriate electric utility. Furthermore, most co-generation projects to date have involved generating capacities much larger than those associated with SPPs.

Benefits to Alberta

The Board recognizes that favourable wind regimes occur in much of Alberta, creating considerable potential for development of wind-powered electric generation. The development of wind-powered electric generation, and the possibility of other forms of small power production which would utilize renewable resources, would be desirable even at a modest scale as environmentally sound energy sources that would conserve non-renewable resources. The economics largely remain to be tested and proven. The development of small power production facilities could conceivably provide a unique opportunity for modest economic benefits to Alberta's agricultural industry as well as job opportunities in the design, manufacture, and installation of such facilities. It is apparent that the technology in this area has made considerable progress in recent years. The Board accepts that the technology exists to make the small power production both safe and compatible with the AIS.

In light of the potential benefits, and considering the need for information on the operation of SPP facilities appropriate to the Alberta energy scene, the Board believes that a suitable environment for development of small power production facilities is advisable for a trial period.

Interaction of SPP Facilities and Utility Systems

In considering the suitability of SPP facility development, it is necessary to consider their interaction with a large electric utility system and the AIS. The Board observes that major impacts such as the addition of a power plant, a large industrial consumer, or even an industrial co-generator can be measured and predicted with some degree of accuracy. When it comes to an SPP, the effects are small and measured in minute increments of utility operations. The Board concludes that although the effect may indeed be real, the arguments as to their nature tend to be hypothetical simply because any measure of an impact is lost in the myriad of other small loads on the system. The major issue surrounding the development of small power production usually revolves around the benefits such facilities provide to the AIS, and accordingly, what the price of surplus energy delivered to the AIS should be. The Board believes that one approach to resolving this problem exists in the statistical methods used by the utilities to plan for the numerous small loads scattered throughout the system. While no individual small load causes a utility to add a generator, the cumulative growth can be estimated within certain confidence limits, and it is this aggregate of small loads which ultimately creates the need for additional generators. The degree of confidence depends on both the large number of small loads and the utilities' experience in planning for and servicing small loads.

Similar experience does not exist for SPPs, however, the Board believes the methodology would be appropriate and should be more useful than the essentially hypothetical arguments. Although these arguments cannot be discarded entirely, only operating experience with SPP facilities will provide any resolution. A concerted effort should therefore be made to obtain valid information on the operation and interaction of SPPs with the AIS. The Board believes that the installation and operation of special instrumentation for such purposes, ie other than standard meters for billing, should be the responsibility of the utility. This detailed information on the performance of an SPP facility is fundamental to determining the relationship to the utility in respect to peaking coincidence, capacity, and potential for some degree of dedication of capacity. The utilities have the expertise for such an evaluation at the common interface with SPPs and are also able to observe the overall impact of SPPs on the system.

Economic Considerations

For any individual SPP to provide the quality of service available from a utility would require several generators, spinning reserve, and perhaps even energy storage at the SPP facility site. It is very unlikely that this would be cost competitive with large-scale utility generation.

In fact, economic analysis similar to that which a utility would use to evaluate a new generating source would indicate that small power production facilities are probably not as economic as utility service. However, the SPP utilizing a renewable resource to supply part or all of its own load, and generating some surplus for sale to a utility, may be in a better position from its own viewpoint. In the case of a farm operator, there is apparently the satisfaction of self-sufficiency and the knowledge of predetermined electric energy costs. In some cases, the SPP might have tax advantages that would make the installation economically attractive to the operator even though unattractive under utility financing.

While the Board is concerned about conservation of any energy resource, it cannot ignore economic and efficient recovery of it anymore than it can ignore economic and orderly development of the AIS. At the hearing of the Sinnott application there was a consensus that neither SPPs nor the utilities and their customers should subsidize one another. In developments to date, initiative has been shown by the few SPPs and there has been co-operation by the utilities to conserve the energy produced.

Interim Policy

As noted before, the Board does not believe it is possible at this time to calculate in great detail the effects, and hence the costs and benefits, of an SPP facility. Instead, the following is presented as a basis for a suitable compromise between the interests of the SPP and utilities for an interim trial and learning period.

The Board expects that small SPPs will request interconnection with the utility for technical reasons, back-up supply, and to feed surplus energy back to the utility. So in a real sense the SPP continues to be a customer and a load to the utility, and the net energy in kilowatt hours (kWh) and the peak load demand in kilowatts supplied by the utility would be billed at a similar rate as for other customers with similar loads.

To the extent that the SPP reduces its own load on an annual and peak time basis, it will on average reduce utility generation and tend to delay new generators, thereby reducing AIS cost. Conversely, if it takes little net energy but continues to take full power demand at time of system peak, it will not delay additional generation and, again on average, could tend to reduce the AIS load factor and thereby slightly increase generating costs.

Turning to energy fed back into the AIS and theoretically distributed to nearby utility customers, the Board expects that the only effect on the utility will be a nearly negligible reduction in the actual on-line AIS generation.[1] Whatever surplus energy the SPP produces would be absorbed by other customers of the utility at that moment and paid for by them at a fixed rate, and for its customers other than the SPP the utility sees no change. The utility will continue to recover its revenue from all other customers as though there were no effect from the SPP. The only "change" seen by the utility, if it is really a change, is that the SPP has on average taken less kWh from the system than it would have as a pure load. Admittedly, the utilities would have some increased administrative costs due to SPPs.

For these very general and admittedly simplistic reasons, the Board believes that very simple cost-recovery procedures should be applied during a trial or learning period during which the impact of SPPs should be studied. During this trial period, the Board expects there will be few SPPs and their effect on the AIS will be minimal. If the simple cost procedures as proposed are in error, then in the interim the error should probably be absorbed by the much larger utilities and the many customers of the AIS in the interest of conservation. The SPPs should in turn be content to receive some but not all of the perceived but not proven benefits of their pioneering.

The simple procedures that the Board believes should be applied during the trial period would regard an SPP as a load on the AIS. As with any customer load that is managed by the customer to conserve energy, that load will probably be less than it would have been without such management. Application of what has been termed "net energy billing", in which one meter records supply to an SPP and another the energy flowing to the system from the SPP should present no great hardship to the utility but would provide a substantial advantage to the SPP that is able to "bank" its energy with the utility and withdraw it as needed.

Very simply, for the trial period, an SPP should be allowed to displace utility generation, and to recover that energy from utility generation at some other time. The Board recognizes that hydroelectric power plants can store energy but it is not convinced that SPP energy would actually be stored. Therefore, for the present, it regards the energy exchange under net energy billing as more in the nature of a banking arrangement that the utility provides as a service to the SPP. If during a normal billing period (probably quarterly) the SPP consumes more energy than it produces, then the SPP would be billed at the usual rates for *net* energy supplied. If the SPP produces more energy during a normal billing period than its own requirements, then the utility should compensate the SPP for excess energy at the true value of the energy to the utility and its other customers. Normally this value will be the utility's avoided cost and will be less than the rate charged for net energy supplied to the SPP.

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[1] The Board recognizes that the effect is real but is probably so small as to be lost among all the other loads continually varying on the system.

In determining the true value of such surplus energy, the Board believes there could well be some capacity contribution by an SPP but the value of any such capacity cannot be determined at this time. However, the Board believes any capacity contribution would almost certainly be more than compensated by the reduction in energy cost to the SPP under net energy billing. The Board believes that any cost to the utility of foregoing the energy charge for kWh the SPP produces for itself would be minimal, but in any case is a reasonable cost during the experimental period for this form of energy conservation. The utility in turn should recover through demand charges and connection contribution its true cost of capacity that the SPP load imposes, just as it would for any other with a similar service. This may be covered by the fixed charges for service or, in some cases, by some form of demand metering; but the Board believes it should be a true utility capacity cost and should not diminish the value of SPP-generated electricity. If the utilities are convinced the present rate structure does not adequately cover cost of capacity in such circumstances, the Public Utilities Board should be asked to determine an appropriate rate.

As stated previously, there are some benefits to the AIS of SPP-installed capacity that are not quantifiable at this time but would be compensated by net energy billing. The Board believes that TransAlta's suggested avoided fuel cost calculated on the basis of 50 per cent gas-fired energy and 50 per cent coal-fired energy is a suitable compromise as compared to the most expensive avoided fuel on the AIS. Savings in line losses at the transmission as well as the distribution level may exceed 5 per cent, but 5 per cent is appropriate during the trial period. The Board believes that it would be fair to SPPs in the interim and also without substantial subsidy by the utilities and their customers. Furthermore, this rate should be reviewed and adjusted as the cost of service is adjusted by the Public Utilities Board from time to time. The Board makes this recommendation without prejudice to the true impact of SPPs that may be determined over the trial period. The Board also notes that an SPP must recognize that further study may show that the value of an SPP to the AIS using this approach is overrated and lower credits might be implemented after the trial period. Correspondingly, if the benefits are clearly demonstrated to be higher, the credits to the SPP for surplus energy may be increased.

Trial Period

As noted before, and until more complete information is available, the Board believes this simple procedure favours the SPP that improves energy conservation by reducing load on the AIS or by generating surplus energy. The utilities may be carrying some small cost over the experimental period and both the period and the number of SPPs should be modestly restricted. The Board believes the experimental period, during which the utilities should ensure that adequate information is obtained and discussed with SPPs and the Board, should be for about five years until 31 December 1989. Such a period would allow for several other SPPs to be connected to the AIS after the Sinnott machine is in service, and still allow several years for evaluation of such SPPs. Should the number of SPPs increase much more rapidly than presently expected, the experimental period should end sooner and the whole question of equitable cost and the economics of conservation should be reviewed.

The Board recommends that, if and when the number of SPPs on the AIS reaches 150 or the total connected SPP generation equals 10 000 kilowatts, the experimental period should end and a report of their impact should be rendered. Furthermore, the Board believes the total SPP generating capacity connected to any one distribution feeder should not exceed half the utility substation supply capacity to that distribution feeder unless the utility operator can satisfy the Board that some other amount is more appropriate.

During the experimental period each utility, assisted by SPPs on its system, should obtain technical and cost information on the operation and interaction of SPPs with the AIS and submit to the Board an annual report by 31 March on the operations to the end of the previous year, and a final summary report by 31 July 1989.

Interconnection Costs

The Board believes that all interconnection costs incurred by the utility beyond those required to connect a customer of similar service, size, and class should be paid by the SPP. Costs of special test metering during the trial period should be borne by the utility. In addition, all costs incurred by the SPP to allow the safe and reliable operation of its generation as part of the AIS should be borne by the SPP. The basic premise on costs should be that all parties agreed that neither the SPP nor the utilities should subsidize one another. Matters relating to liability and insurance were raised at the hearing. The Board believes these matters relate to a normal business transaction between the SPP and the utility and should be resolved between the parties, but suggests that the utilities take into account their treatment of existing customers who have installed standby generation. The Board recognizes and accepts that all parties are entitled to and must protect their own interests, but would hope this can be accomplished without resorting to a purely legalistic approach.

SUMMARY

The Board found that some of the issues raised to date may be relevant but their impact is indeterminable at this time. However, three points did stand out from all the discussion and argument about the impacts and relationships of a small power producer and an electric utility.

- A small power producer generating wind-powered energy cannot fully utilize and conserve such energy for its own purposes without some means of matching the availability of that energy to the small power producer's own load. Such means of matching are not available at reasonable cost independent of the larger interconnected electric system.
- An electric utility is a customer-oriented regulated enterprise that provides needed electric service at the lowest reasonable cost. Over the years to date, electric utilities have been innovative in meeting the needs of their customers through new types of services and the development of new forms of contracts that recognized the true cost of providing service.
- The parties agreed that they should not subsidize one another, and that each should be able to pursue its business without acquiring costs or benefits of the other party. There appeared to be no quarrel with charging or paying for actual costs or benefits – what disagreement there was arose from different understandings and perceptions of impacts, costs, and benefits.

The Board concludes the available evidence at this time does not provide an answer as to the true impact of SPPs on the AIS. The Board does not consider it proper to impose a compromise somewhere between the opposing perceptions of reality. What should be provided is the service the customers need, and the Board sees this as a banking service by utilities for wind-generated electricity and not as storage on the interconnected electric system. Naturally, there is a cost to providing such a service and the true cost remains to be determined. In the interim, a simple means of implementing the service on a trial basis for five years has been put forward. The banking service will probably not result in a perfect matching of customer generated energy with customer load, and any net energy supplied by the utility should be charged at normal utility rates and any net surplus energy generated and delivered to the utility should be at the avoided energy cost actually realized by the utility. The basis for determining the latter is proposed to be at 50 per cent gas-fired energy and 50 per cent coal-fired energy, plus about 5 per cent credit for avoiding line losses. Actual rates should be determined by the Public Utilities Board and adjusted as required.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ENHANCED RECOVERY
PEMBINA NISKU N POOL
CANADIAN RESERVE OIL AND GAS LTD.
TEXACO CANADA RESOURCES LIMITED

Decision D 84-13
Applications 830847 and 840013

1 INTRODUCTION

Canadian Reserve Oil and Gas Ltd., on behalf of itself and BP Exploration Canada Limited, applied pursuant to section 26, clause (a) of the Oil and Gas Conservation Act (the Act) for approval of an enhanced recovery scheme by water injection in a portion of the Pembina Nisku N Pool (N Pool). Texaco Canada Resources Ltd., as an offset owner in the N Pool, and in response to a Board request, submitted an application pursuant to section 26, clause (a) of the Act for approval of an enhanced recovery scheme by hydrocarbon miscible flood. The hearing was thus called to consider both applications and to determine the appropriate enhanced recovery scheme for the N Pool.

1.2 The Hearing

A public hearing was held on 27 March 1984 with N. Strom, P.Eng., C. J. Goodman, P.Eng., and F. J. Mink, P.Eng., sitting. Participants at the hearing are listed in Table 1.

1.3 Background

The N Pool was discovered in April 1979, with the drilling of the well, GETTY BP PEMBINA 6-12-50-11 W5M, and further delineated by the wells, GETTY BP PEMBINA 12-12-50-11 W5M and TEXACO PEMBINA 9-11-50-11 W5M. The pool is an isolated pinnacle reef with an oil/water interface but is not connected to an active aquifer. Consequently, the reservoir pressure declined rapidly with production from the initial pressure of 27 426 kilopascals (kPa) to approximately 20 160 kPa in March 1980. At that time, production operations were voluntarily suspended to prevent the reservoir pressure from dropping below the bubble-point pressure of the oil pending implementation of an enhanced recovery scheme.

After approximately 3.5 years of studies and negotiations, the operators concluded that unanimous agreement could not be reached respecting the appropriate enhanced recovery mechanism for this pool. CROGL and BPX, as joint owner of the major portion of the pool, elected to

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canadian Reserve Oil and Gas Ltd. (CROGL) and BP Exploration Canada Limited (BPX) C. K. Yates	G. Thomas, P.Eng. A.T.W. Patrick, P.Eng. P. W. Pantella, P.Eng. R. I. Benteau, P.Geol.
Texaco Canada Resources Ltd. (Texaco) D. G. Hart, Q.C.	K. M. Braaten W. R. Hovdestad, P.Eng. D. N. Turnbull, P.Eng. W. S. Kolodinsky, P.Eng. D. D. Hansen, P.Geol. N. R. Watts A. A. Gorden, P.Eng.
Energy Resources Conservation Board staff C.J.C. Page R. J. Willard, P.Eng. K. Kadonaga, P.Eng. R. M. Feick	

proceed with an application to implement a waterflood scheme in its respective area.

In response to an ERCB staff query, Texaco submitted its views opposing the waterflood scheme and supporting the implementation of a hydrocarbon miscible flood scheme. In order to permit a full evaluation of the depletion alternatives, Texaco was then requested to submit an application for approval of a miscible flood scheme for the N Pool.

2 ISSUES

Considering the views held by the three mineral rights owners, the Board believes the major issue to be the appropriateness of implementing either a waterflood scheme or a miscible flood scheme in the N Pool having regard for the recoverable reserves and the associated economics of each alternative.

A considerable amount of information and data was presented in the two applications and subsequent submissions and through testimony at the hearing. During the course of evaluating the applications, several key matters were identified to which the recovery or economic results were particularly sensitive. The discussion in the following sections of the report will focus on these key factors. Those matters in which there was substantial agreement or which were judged to be of relatively minor importance will not be specifically addressed.

2.1 Recovery and Performance Sensitivities

2.1.1 Views of CROGL (and BPX)

The reservoir performance prediction presented by CROGL was based on a reservoir simulation study performed by Petresim Engineering Ltd. (Petresim) which included evaluations of both waterflood and miscible flood cases. The simulation model was constructed on the basis of a geological model which used an apparent "tight layer" in the water zone as a stratigraphic datum. According to this geological interpretation, several tight anhydrite layers in the oil column near the top of the reservoir were considered to be correlatable between wells, and therefore representative of potential areally-extensive permeability restrictions or barriers to vertical flow. This geological interpretation also identified deteriorating reservoir qualities near the top and the edges of the reef.

CROGL used a waterflood residual oil saturation (Sorw) of 0.35 and a miscible flood residual oil saturation (Sorm) of 0.05 in its simulation studies on the basis that these values were representative and generally accepted by industry in the area. CROGL acknowledged that a range of values was possible for both parameters but suggested that actual values for the N Pool could not be determined from currently available data.

As regards conformance effects and sandwich loss thicknesses, CROGL accepted the model results as being reasonable and appropriate. However, during cross-examination, CROGL stated that, in its view, the model formulation would tend to result in an optimistic prediction with respect to sandwich thickness. Further, CROGL stated that, whereas the model predictions indicated a sandwich thickness in the order of 4.5 metres (m) in the miscible flood case, the actual sandwich thickness could be in the range of 5 to 10 m. The conformance factor was estimated to be about 90 per cent for the waterflood and 85 per cent for the miscible flood.

CROGL estimated recoveries would be 49.4 per cent for waterflood and 65.0 per cent for miscible flood. CROGL further stated that waterflood recoveries could range from a low of 42 per cent to a maximum of 52 per cent. Miscible flood recoveries could range from a low of 48 per cent to a high of 68 per cent.

2.1.2 Views of Texaco

Texaco's geological interpretation of the reservoir divided the reef into two geological zones identified as the Wolf Lake member (the upper zone) and the Zeta Lake member (the lower zone). The Wolf Lake member, with an approximate thickness of 15 m in the wellbores, was described as having poorer reservoir qualities than the Zeta Lake member and with zones of impermeable anhydrite cementation. The anhydrite infilled zones were described as randomly distributed patches of limited areal extent and were not believed to be correlatable between wells. The Zeta Lake member formed the major body of the reef and was further divisible into upper and lower units.

Texaco maintained that, in a miscible flood, the anhydrite patches in the Wolf Lake member would not impede the vertical displacement of the solvent and that a sandwich thickness of 3 m or less would be attainable. On this basis, and assuming an Sorm of 0.05, Texaco predicted a miscible flood recovery of 71 per cent. Texaco also argued that the recovery could be as high as 82 per cent assuming an Sorm of 0.03 and a sandwich thickness of 1.5 m.

For the waterflood, Texaco predicted a recovery in the order of 42 per cent, based on an Sorw of 0.41, a conformance factor of 0.85, and a combined sandwich and attic thickness of approximately 9 m.

2.1.3 Views of the Board

The Board has reviewed the compendium of technical information filed by the three operators in the N Pool and notes that there was considerable agreement respecting several aspects of reservoir definition. However, there was also a considerable divergence of views respecting three or four key reservoir factors.

The Board is satisfied that the interpretation of hydrocarbon pore volume versus depth, although subject to considerable potential variance due to limited drilling information, was one matter in which all parties were essentially in agreement. Therefore, for the purposes of further consideration of the evidence, the Board adopted the interpretation shown in Figure 1.

Regarding the geological properties of the reef, the Board notes that, despite significant differences in interpretations of the depositional and diagenetic history of the pool and of the internal facies distributions, both CROGL and Texaco recognized that the uppermost portion of the reservoir is of lower quality and contains impermeable, anhydrite-infilled sections. The key difference of the interpretations was whether the anhydrite-infilled sections were pool-wide and would constitute major flow barriers. Based on the evidence presented, the Board has concluded that the anhydrite-infilling is likely to be random and localized. Thus, it should not represent major restrictions to vertical displacement. As well, the Board believes that, although this lower quality reef section and the anhydrite patches contained in it could affect the performance of individual wells, the vertical downward displacement of miscible fluid through the upper part of the pool would not be affected nor would the recoveries under waterflood be significantly reduced. The Board believes that conformance efficiency will be comparatively high for either waterflood or miscible flood and adopts a value of 0.90.

The Board concludes that the residual oil saturations and sandwich loss effects would have the greatest influence on the recovery under either waterflood or miscible flood. While Sorm theoretically could be zero, the Board considers it appropriate to continue to assign the generally accepted value of 0.05. Similarly, while Sorw values ranging from 0.25 to 0.50 have been demonstrated to be possible from laboratory and performance studies on other reefs, the Board believes that an Sorw of 0.35 is a reasonable estimate for the N Pool. Thus the Board concludes that Sorw minus Sorm ($\triangle$ Sor) would be 0.30.

It is clear that the sandwich thickness in a vertical miscible displacement process can have a major impact on the anticipated recovery from the pool. The Board observes that the reservoir properties in the basal portion of the N Pool are of very high quality. Thus, with appropriate well completion and operation practices, the Board considers a sandwich thickness in the order of 3 m to be a reasonable expectation.

With respect to the sandwich and attic losses for the waterflood case, the Board notes that the top of the reservoir is interpreted to be 3.6 m above the top of the highest well in the pool. Considering the poorer quality of the reservoir in this section, the Board believes that the combined sandwich and attic losses for a waterflood scheme would be in the order of 8 m.

Table 2 shows the incremental recoveries (miscible flood minus waterflood) for various miscible flood sandwich thicknesses and a $\triangle$ Sor of 0.30.

TABLE 2 SENSITIVITY OF INCREMENTAL RECOVERY TO MISCIBLE FLOOD SANDWICH THICKNESS

MF Sandwich Thickness (m)	Incremental Recovery Factor ($\triangle$ Rec.) (%)
2	24.0
3	19.8
4	15.6
5	11.4

Having regard for its previously stated conclusions, the Board believes that the incremental recovery would be about 20 per cent. However, in examining economic risk, an assumption of a 4-m miscible flood sandwich should be considered.

For the purposes of establishing reserves for the N Pool, the Board adopts recovery factors of 45 per cent for the waterflood and 65 per cent for the miscible flood.

2.2 Associated Economics

2.2.1 Views of CROGL (and BPX)

To assess the attractiveness of the miscible flood scheme, CROGL calculated the rate of return (ROR) on the difference between the miscible flood investment and the waterflood investment, and the incremental present worth (PW) using various discount rates. For its base case, CROGL used the forecasts from cases W2 and M9 of the Petresim Study which predicted that the miscible flood scheme would result in an improvement in oil recovery of some 16 per cent over the waterflood scheme.

As shown in Table 3, CROGL estimated that \$1.65 million would be required to implement the waterflood scheme whereas the miscible flood scheme would involve a capital outlay of \$7.69 million. These costs were based on CROGL's experience in constructing the Pembina Nisku M Pool facilities.

TABLE 3 OPERATOR INCREMENTAL ECONOMICS ASSUMING SECTION 4.2 RELIEF

	Canadian Reserve Evaluation	Texaco Evaluation	Board Base Case	Board Sensitivity Case
Capital Costs (millions 1984$)				
Waterflood	1.650	2.494	1.911	1.911
Miscible Flood	7.693	6.843	6.755	8.255
Incremental	6.043	4.349	4.844	6.344
Incremental Recovery (%) (Miscible Flood minus Waterflood)	16	29	20	16
Blowdown Period (yrs)	20	10	10	15
Incremental ROR (%)	< 20	67	44	21
Incremental Discounted Present Worth (millions $)				
10%	N.A.	28.205	13.527	10.569
20%	-0.726	9.296	1.846	0.151

To estimate the miscible flood capital costs, CROGL assumed that gas driven compressors would be used and that water disposal and natural gas liquids (NGL) supply would be carried out by trucking services. In addition, a 6-month start-up difference was anticipated between the implementation of a miscible flood scheme and the implementation of a waterflood scheme. The miscible flood evaluation, including a 20-year blowdown period, resulted in an incremental ROR of less than 20 per cent and a PW discounted at 20 per cent of minus $0.726 million. If the blowdown period was reduced to 10 years, CROGL showed that the discounted PW of the project would be minus $0.466 million. However, in cross-examination, CROGL stated that the benefits derived from blowing down the reservoir should not be included in an economic analysis of the relative merits of a miscible flood scheme versus a waterflood scheme.

With respect to the suitability of these economic indicators from a corporate perspective, both CROGL and BPX indicated that an appropriate minimum ROR should be not less than 15 to 20 per cent. However, both companies stressed the importance of risk considerations in their decision making process and suggested that an analysis which attached probability statements to alternative outcomes was their preferred method of analysis. After accounting for risk, the PW discounted at 20 per cent became minus $1.407 million.

2.2.2 Views of Texaco

The economic evaluation carried out by Texaco was performed in a manner similar to the CROGL analysis. Texaco focused on the expected incremental ROR and the level of producer profit at several discount rates. Texaco's base case assumed an incremental recovery of approximately 29 per cent for the miscible flood.

Texaco estimated that the capital investment required to implement a waterflood in the N Pool would be $2.49 million, some $0.844 million higher than CROGL's estimate. Texaco's estimate of the capital necessary to implement the miscible flood scheme was $6.84 million or approximately $0.850 million less than the CROGL projection.

The investment base for the miscible flood project included the cost of an electric driven compressor rather than gas driven, and the costs of two pipelines, one to dispose of water and the other to supply NGLs. Texaco anticipated that there would be no start-up delay between the two projects and assumed that the blowdown phase would occur over 10 years. Texaco's cost estimates were based on its experience with other schemes in the West Pembina Area.

Texaco's analysis showed that the expected incremental ROR for the miscible flood was 67 per cent with an incremental present worth discounted at 20 per cent of $9.30 million. From a corporate viewpoint, Texaco indicated that a suitable guideline for the minimum acceptable ROR would be 20 per cent. With respect to risk analysis, Texaco submitted that it generally relies on a judgemental assessment of sensitivity studies as a means of recognizing risk. In the case of the N Pool, Texaco indicated that, in light of technical and economic uncertainties, it was comfortable with the economic return indicators generated by its analysis.

2.2.3 Views of the Board

The Board agrees with both of the applicants with respect to the appropriateness of the incremental rate of return and the discounted present worth as suitable economic indicators. The Board has, therefore, chosen to examine these indicators as they result from a base case comprised of the most likely recovery factors.

The Board agrees with Texaco and CROGL that the incremental investment necessary to implement a miscible flood scheme in the N Pool will not yield an acceptable return if royalty relief under section 4.2 of the Petroleum Royalty Regulations is not granted. Accordingly, in its analysis, the Board assumed that full section 4.2 credits would be available. The Board notes that the major factors contributing to the difference in the investment estimates provided by the parties were the types of gas compression equipment and the transportion modes assumed for NGL supply and produced water disposal. The Board accepts the arguments raised by Texaco that electrical compressors are more cost-effective and are sufficiently reliable for miscible flooding operations. Accordingly, it has incorporated costs to reflect these facilities in its investment estimate.

Considering the volumes of produced water and the duration of operations, the Board also believes that water disposal for the miscible flood case would likely be achieved more efficiently via a pipeline rather than by trucking as assumed by CROGL. The Board expects that in light of the short NGL injection period it is likely that an NGL supply line will not be built, although it recognizes that this likelihood will decrease if more miscible flood schemes are implemented in the immediate vicinity. The Board's estimates of likely capital investments for both schemes are shown in Table 3.

The Board notes that the applicants provided similar cost estimates for the other capital items. While the Board recognizes that there may be some increased complexity to implementing a miscible flood scheme, and further, that approval of an application for section 4.2 royalty relief would require some time, it does not expect these differences to be sufficiently significant to assume a lag in the start-up of the miscible flood. The Board is satisfied that the gas recovery phase of a miscible flood scheme should be included in the project evaluation inasmuch as the costs of the injected fluids are considered during the operation of the scheme. Further, as the blowdown would occur at a time of expected declining deliverability in the province and of sustained or growing demand, the Board expects that deliverability-type contracts would be available. Accordingly, the Board has assumed a blowdown period of 10 years in its base case evaluations. However, it is noted that the assumption by the Board of a constant rate over the 10-year period is conservative considering that gas production in the early years of blowdown will likely be higher than the annual average. The Board's base case evaluation indicated an incremental ROR of 44 per cent and a present worth discounted at 20 per cent of $2.846 million.

The Board agrees with the view that the uncertainties surrounding key variables should be considered in an economic evaluation of this nature. For this reason, the Board has examined an alternative case in which the incremental recovery was reduced to 16 per cent. The Board took this opportunity to examine the impact of possible adverse economic factors including: increased capital costs for installation of gas driven compressors, an extended blowdown period of 15 years, and a 6-month start-up lag for the miscible flood. The sensitivity analysis indicated an incremental ROR of 21 per cent and a present worth discounted at 20 per cent of $0.151 million.

The results of the Board's economic evaluation compared to the results of the CROGL and Texaco evaluations are shown in Table 3. The Board is of the opinion that the sensitivity case represents a pessimistic view of the economic parameters and the lower bound for probable incremental recovery. The Board, therefore, concludes that irrespective of the compressor choice or assumed blowdown period, the incremental investment would generate a return in excess of 20 per cent, a rate which both applicants agreed is an appropriate guideline for the minimum ROR. The Board also notes that a potential for improving the economic benefits exists if the operators were to take advantage of available short-term discount gas.

3 SUMMARY CONCLUSIONS

The Board has given due consideration to the submissions and evidence of the applicants and concludes the following:

- A vertical displacement hydrocarbon miscible flood is technically feasible and would result in a conservation gain of 20 per cent of the oil in place or approximately 320 thousand cubic metres of oil over a waterflood scheme.
- From an operator perspective, the economics of miscible flood should be favourable if section 4.2 relief is received, but would be unfavourable if not received.
- From a public interest perspective, a miscible flood would provide not only additional oil reserves, but also other benefits including expansion of internal gas markets and generation of greater service and supply industry activity than would a waterflood.
- A vertical displacement hydrocarbon miscible flood is a preferred enhanced recovery process for the N Pool.

4 DECISION

The Board denies Application 830847, a proposal to waterflood the Pembina Nisku N Pool, and approves Application 840013, a proposal to miscible flood the Pembina Nisku N Pool. Also, the Board directs that the Pembina Nisku N Pool remain shut in until a miscible flood scheme is implemented. The Board understands that the operators would wish to obtain a prompt ruling on section 4.2 royalty relief eligibility. To that end, the Board undertakes to ensure expeditious consideration of referrals of a section 4.2 application from Alberta Energy and Natural Resources.

DATED at Calgary, Alberta, on 14 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

N. Strom, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

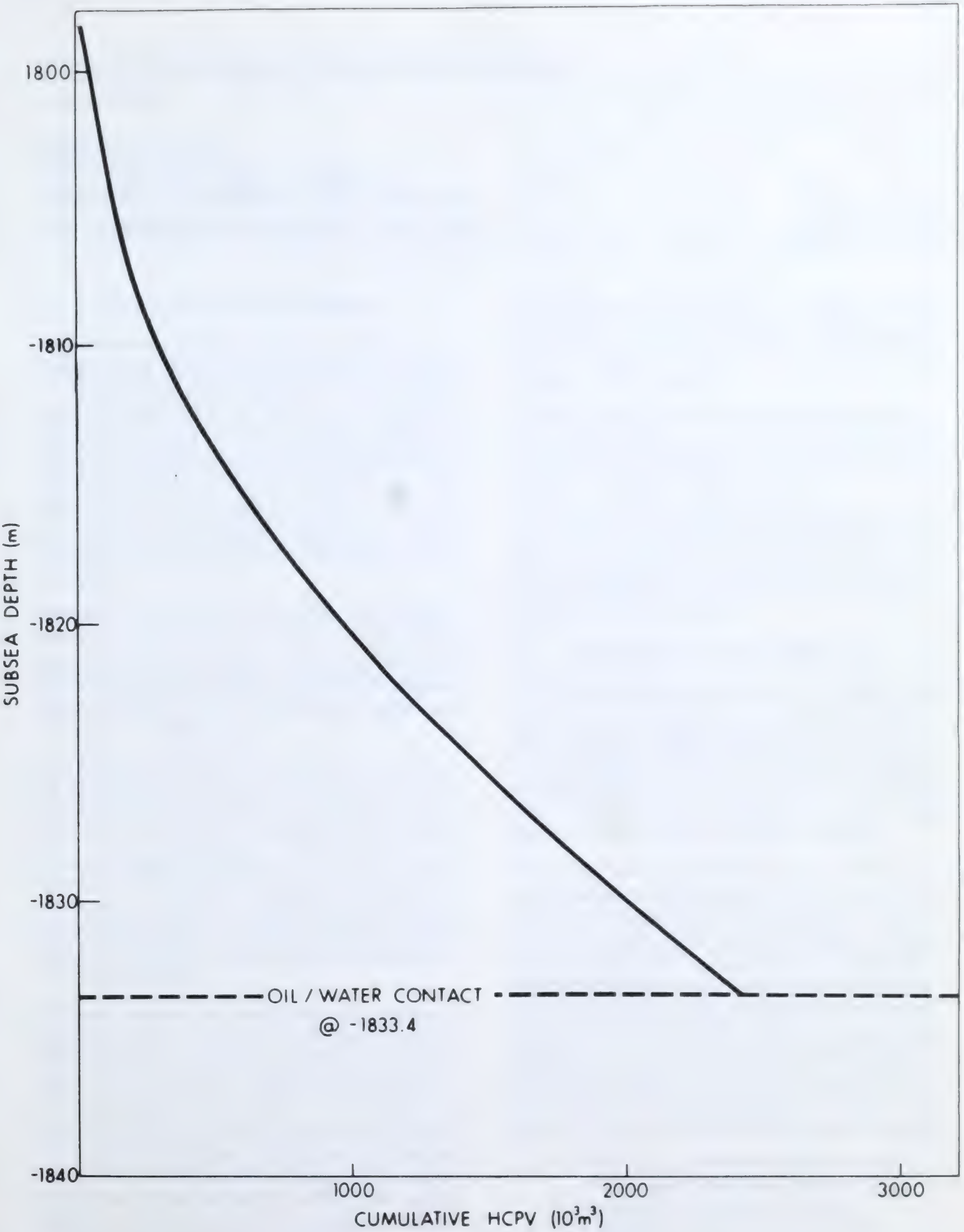


FIGURE 1 PEMBINA NISKU N POOL
HYDROCARBON PORE VOLUME VS. DEPTH

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY ESSO PETROLEUM CANADA, A DIVISION OF IMPERIAL OIL LIMITED TO AMEND ERCB APPROVAL HE 8208

Decision D 84-14
Application 840136

1 APPLICATION AND HEARING

Esso Petroleum Canada, A Division of Imperial Oil Limited (Esso) applied to the ERCB under clause 8(b) of Approval HE 8208, section 42 of the Energy Resources Conservation Act, and section 5 of the Hydro and Electric Energy Act for an order amending the approval by altering the boundary of the electric distribution system and service area of the City of Edmonton (Edmonton Power), as established in the said approval, by excluding the Esso south tank farm, and/or for such further orders and/or directions as the Board may deem appropriate.

The south tank farm is now within the City of Edmonton but remains an integral part of the industrial complex of the Strathcona refinery which is adjacent to the City of Edmonton. The attached figure shows these areas relative to the city boundary, the electric service area boundary, and Highway 16A.

In Board Decision 82-16, which resulted in Approval HE 8208, the Board noted that no one argued compelling reasons not to transfer the area applied for, nor did the Board find compelling reasons not to do so. Several of the participants requested, and Edmonton Power agreed, that Edmonton Power honour all power-supply contracts for customers transferred from TransAlta Utilities Corporation (TransAlta) to Edmonton Power. They further asked that a clause to that effect be included in Approval HE 8208.

The Board now notes that, at the time of the public hearing that resulted in Decision 82-16 and Approval HE 8208, Esso did not intervene nor did any other party raise the possibility of any large industrial load being split if the application for transfer of service area were granted. At that time, the Board contemplated the supply to each individual customer as falling wholly within the service area of either Edmonton Power or TransAlta, and saw those customers with individual power-supply contracts as having their contracts honoured by one but not both of Edmonton Power or TransAlta.

The two electric utilities were allowed a period after the transfer, until early 1983, to complete negotiations and agree on compensation or return to the Board for further direction. Physical alterations to the actual supply facilities were also carried out in the period following issuance of the approval.

A public hearing of the current application was held in Edmonton, Alberta, on 14 May 1984, with Board members G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng. sitting.

Edmonton Power, TransAlta, Fiberglas Canada Inc., Industrial Power Consumers Association of Alberta, and Energy Resources Conservation Board staff intervened upon the application. The participants at the hearing are listed in the following table.

2 POSITION OF THE APPLICANT

Esso stated that prior to the issuance of Approval HE 8208, its refinery complex, which includes the south tank farm, had been served by TransAlta. Since the effective date of the approval, TransAlta has served the refinery and Edmonton Power has served the tank farm. The actual physical supply facilities have changed only slightly to allow service from the two utilities.

While being served by TransAlta, the electricity used at the tank farm was summated with that used at the refinery, in accordance with the conditions of a power-supply agreement between Esso and TransAlta, as though there was effectively one point of supply. Since the effective date of the order, the electricity has not been summated but has been charged and billed separately by each utility as though the refinery complex constituted two separate loads. According to Esso, this has resulted in higher costs by some $8 thousand per month. Esso thus contended that Edmonton Power is not complying with clause 5 of Approval HE 8208 which reads as follows:

> 5. The City of Edmonton shall honour all of the existing individual power contracts between TransAlta Utilities Corporation and its customers in the transferred areas.

Esso stated that it is requesting an amendment of the Edmonton Power service area to exclude the tank farm

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Petroleum Canada, A Division of Imperial Oil Limited (Esso) D. G. Hart, Q.C.	J. F. Zupanic, P.Eng. G. T. Belban, P.Eng.
The City of Edmonton (Edmonton Power) Marilyn McAvoy	Bernard Hiron, P.Eng.
TransAlta Utilities Corporation (TransAlta) E. J. McCoy	G. D. Lyons, P.Eng. E. W. Smith, P.Eng.
Fiberglas Canada Inc. (Fiberglas Canada) K. D. Wakefield	
Industrial Power Consumers Association of Alberta (IPCAA) J. F. Eigner	J. F. Eigner
Energy Resources Conservation Board staff C.J.C. Page H. R. Hansford	

but would, in the alternative, accept any possible Board action which would rectify the situation.

Esso stated that the Board has jurisdiction to take action in a number of ways. One related to clause 8(b) which provides:

> 8. The Board may,
>
> (a) upon its own motion, or
>
> (b) upon the application of an interested person, rescind or amend this approval at any time.

Esso disagreed with a suggestion of the Board staff that the interested party referred to in this clause should be interpreted in a limited way which might result in the exclusion of Esso.

The applicant also suggested that action could be taken by the Board in the form of a review of its 1982 decision in accordance with section 42 of the Energy Resources Conservation Act.

> 42. The Board may review, rescind, change, alter or vary any order or direction made by it or may re-hear an application before deciding it.

In the event of such a review, Esso disagreed with a Board staff suggestion that clause 26, subclause (2) of the Hydro and Electric Energy Act might preclude a reduction to the service area. Clause 26(2) reads as follows:

> 26. (2) When a local authority owns and operates an electric distribution system within its municipality, the Board shall not reduce its service area without its consent.

Esso argued that that section of the legislation relates only to reductions in the service area of the various municipalities which would have existed when the legislation initially came into effect in 1971. Esso went on to state that, in its opinion, a review of the approval could be made by the Board under section 42 of the Energy Resources Conservation Act and, if compelling reasons in the public interest exist, changes to the order reducing the size of the service area could be made. Esso argued that the increased costs it is experiencing would represent such compelling reason.

Esso stated that, if the Board saw an alternative solution, action could be taken under section 5 of the Hydro and Electric Energy Act which states:

> 5. The Board, with the approval of the Lieutenant Governor in Council, may make any just and reasonable orders and directions that the Board considers necessary to affect the purposes of this Act and that are

not otherwise specifically authorized by the Act.

3 POSITION OF THE INTERVENERS

3.1 Energy Resources Conservation Board Staff

The Board staff did not present evidence but questioned the applicant and others, and also presented argument. In argument, the staff did not take a position but raised the following legal questions for consideration by the Board.

(a) It was suggested that a review such as is contemplated under section 42 of the Energy Resources Conservation Act should be made only if an error is found, there is a fundamental change in circumstances, or a new matter of principle has arisen. It was further suggested that, if a review were made, the Board may not have the jurisdiction to reduce the service area of Edmonton Power because section 26(2) of the Hydro and Electric Energy Act states that "...the Board shall not reduce its service area without its consent". The staff advised the Board that if it decided to review its earlier decision and, in doing so, effectively revoked the approval and went back to the situation that existed in early 1982, then section 26(3) of the Hydro and Electric Energy Act would require that the expansion to the service area be made unless "...the Board finds compelling reasons in the public interest not to do so".

(b) The question was raised as to whether the reference to "interested person" in clause 8(b) of Approval HE 8208 would include Esso, or whether it would be limited to companies directly affected by the matter such as the holder or assignee of the approval. The staff suggested that Esso might be considered an interested party if clause 5 of the approval is not being satisfied.

(c) The staff pointed out that section 5 of the Hydro and Electric Energy Act does not allow the Board to take actions which are contrary to other provisions of the legislation, for example section 26(2).

3.2 The City of Edmonton

Edmonton Power opposed the application of Esso. It contended that any reduced charges to Esso would not be accompanied by a reduction in the electricity used and consequently the lost revenue would have to be provided by other customers.

Edmonton Power said that, where a consumer carries on business at several different locations, its policy is to not summate power where that consumer has more than one entry and metering point, as was the case with the tank farm and the refinery proper. If the area in question were to be transferred back to TransAlta, Edmonton Power suggested that the transfer cost would run some $70 thousand.

Edmonton Power contended that it is satisfying clause 5 of Approval HE 8208 because the reference is to "customers in the transferred area". Since only the tank farm is in the area, no summation is necessary to meet this requirement. Edmonton Power further suggested that, even if the clause were not being met, a Board hearing is not the appropriate forum for consideration of the matter.

Edmonton Power said that a review of the 1982 decision would be warranted only by significantly changed circumstances which is not the case, but, even if it were, there are no "compelling reasons in the public interest" to justify the requested change.

3.3 TransAlta

TransAlta stated that it took no position for or against the application. It confirmed that it had been summating the power used by Esso prior to the 1982 change of service areas and that it would still be doing so if the changes had not occurred.

TransAlta drew the Board's attention to the Public Utilities Board Act and to its prohibition against a utility providing a preferential rate for any consumer.

3.4 Fiberglas Canada

Fiberglas Canada supported the Esso application. It suggested that it too is experiencing higher charges since the service area change, although for different reasons than is the case with Esso. It argued that the Board did have jurisdiction to make changes and that since the Board had made the order giving the additional service area to Edmonton Power, it is not prevented by section 26(2) of the Hydro and Electric Energy Act from reviewing that decision and reducing the service area.

3.5 Industrial Power Consumers Association of Alberta

IPCAA supported the application of Esso and indicated that other consumers in the area could experience increased billings from the service area changes approved by Approval HE 8208 or other similar decisions. It thus considered the matter important in terms of a precedent.

4 VIEWS OF THE BOARD

In addressing the Esso application, the Board first reviewed the legal matters raised by the Board staff and others at the hearing.

The Board does not agree with the position of Esso and certain of the interveners that the Board can reduce a service area of a local authority, that owns and operates an electric distribution system, without the consent of the local authority. In the Board's judgement, if the section were to be interpreted as applying only to service areas as they existed at the time the legislation was made, it would have said so. The Board thus does not believe it can take the action suggested by Esso of reducing the Edmonton Power service area.

The Board agrees that a review of a decision under section 42 of the Energy Resources Conservation Act should not take place unless new and significant information is available. It considers the knowledge respecting the fact that the service area changes have split the refinery complex, leaving the refinery itself outside the Edmonton area but moving the tank farm within it, to be new information in that it was not revealed at the 1982 hearing. The Board is consequently prepared to review the decision insofar as that limited portion of the area is concerned.

The Board agrees with the staff suggestion that, if the part of the decision which expanded the service area to include the tank farm is reviewed, it is in effect revoking that part of the approval and reconsidering whether the expansion requested in the original Edmonton Power application should be approved. Section 26(3) of the Hydro and Electric Energy Act states that the Board, in a case where a local authority that owns and operates an electric distribution system applies for an enlargement of its service area, shall grant the application unless it finds compelling reasons in the public interest not to do so. The Board recognizes that the expansion of the service area has the impact of increasing costs to Esso unless some other resolution can be found. The Board is not convinced that a resolution cannot be found but, in any case, the Board does not believe that the increased cost to Esso of some $8 thousand per month in a bill of about $550 thousand per month, and in a total cost of greater than $100 million per month for operation of the refinery, would have a sufficient potential impact on consumers to constitute a "compelling reason in the public interest". The Board, on reviewing its earlier decision, is thus not prepared to alter it insofar as the service area expansion to include the corporate boundaries of Edmonton is concerned.

This is not to suggest that the Board is not concerned that the increased cost being experienced by Esso may be as a result of clause 5 of Approval HE 8208 not being implemented, nor does it override the portion of the Board's earlier decision to ensure that all then existing individual power contracts are honoured. The Board observes that although clause 5 refers to "...the transferred area..." there is no individual contract applying to only the tank farm and it is difficult to honour the terms of the refinery complex contract when the billing of the customer is varied in a manner not contemplated in that contract. As noted earlier, the Board was not aware of this possible complication at the time of its earlier decision and approval. Whether the two utilities became aware of the situation during the period granted for negotiation after Approval HE 8208 was issued, but thought compliance with clause 5 would be feasible, is not clear. In any event, the utilities did carry out the changes resulting in the present situation and, now that the Board is aware of the facts, in this particular circumstance the Board does not believe that the spirit of its earlier decision and clause 5 of its approval are being satisfied.

The Board recognizes the unique circumstances of this whole matter, and emphasizes that its determination that the spirit and intent of clause 5 of its original decision are not being carried out relates solely to the terms and conditions of the original contract not being honoured. Some alternatives to resolve the matter would depend upon negotiated arrangements, for example: some form of combined billing might be arranged that would be satisfactory to all three parties; or the supply to the whole refinery complex, including the tank farm, might be through the 138-kilovolt supply point.

The Board believes that negotiations should take place and would be the preferred method of resolving the matter. Accordingly, the Board is prepared to allow up to 90 days for Edmonton Power, Esso, and TransAlta to develop and agree on a workable arrangement in the spirit of the Board's original decision. Failing this, the Board is prepared to take action to reopen the hearing and:

(a) in accordance with section 1(1) of the Hydro and Electric Energy Act, consider whether it should designate Esso's electric system as an industrial system to allow Esso to provide electric energy to its entire refinery complex, including that portion across a public highway; or

(b) in accordance with section 17 of the Act, consider whether it should order an interconnection between the TransAlta and Edmonton Power systems west of the present interconnection to restore the whole load to TransAlta and allow it to reimplement the original contract; or

(c) in accordance with section 26 of the Act, consider expanding the service area of Edmonton Power to include the whole refinery complex and allow clause 5 of Approval HE 8208 to be properly implemented.

The Board will provide three months for these discussions to occur and arrangements to be made to satisfy clause 5. If prior to or at the expiry of that time it is informed that changes cannot be made, it will initiate action to resolve the matter.

5 DECISION

The Board is not prepared to grant the application of Esso and reduce the Edmonton Power service area. However, it does not consider that clause 5 of Board Approval HE 8208 is being satisfied and, unless arrangements are put in place to do so no later than 30 September 1984, the Board will initiate action that will ensure that such is done.

ISSUED at Calgary, Alberta, on 8 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

GJDeSorcy

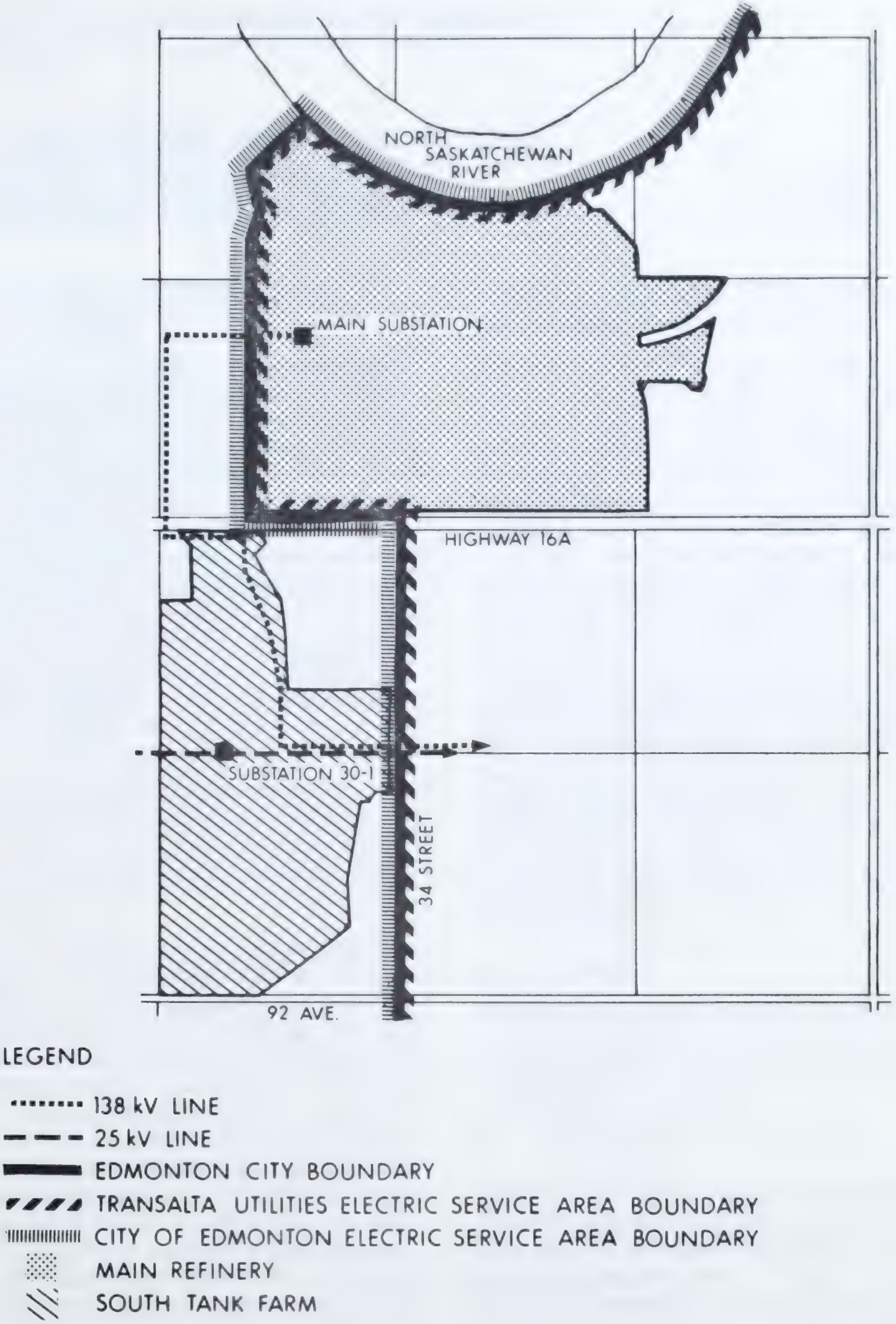
G. J. DeSorcy, P.Eng.
Vice Chairman

VE Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member



STRATHCONA REFINERY AND THE CITY OF EDMONTON ELECTRIC SERVICE AREA

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY ESSO PETROLEUM CANADA, A DIVISION OF IMPERIAL OIL LIMITED, TO AMEND ERCB APPROVAL HE 8208

Addendum
Decision D 84-14
Application 840136

1 BACKGROUND TO REOPENING OF HEARING

On 22 April 1982, the Energy Resources Conservation Board (Board) convened a hearing in Edmonton, Alberta, to consider The City of Edmonton's (Edmonton Power) Application 810819, which requested approval to alter Edmonton Power's electric distribution service area boundary to coincide with the city's corporate limits, and to correspondingly reduce the service area of TransAlta Utilities Corporation (TransAlta). As set out in its Decision Report 82-16, the Board granted the application subject to the service area alteration coming into force 1 August 1982 and Edmonton Power honouring all terms of existing TransAlta service contracts in the area. Approval HE 8208, issued to Edmonton Power, identifies the service area in which the electric distribution system is to operate.

Clause 5 of Approval HE 8208 states that:

> "5. The City of Edmonton shall honour all of the existing contracts between TransAlta Utilities Corporation and its customers in the transferred areas."

The clause was inserted as a result of requests made by participants at the hearing and Edmonton Power's commitment, also given at the hearing, to honour the terms of contracts that then existed between TransAlta and a number of industrial customers in the transferred areas. Edmonton Power's commitment is illustrated in its letters to two of the participants in the hearing, filed as Exhibits 7 and 8, and in responses given, by its witness, to counsel for TransAlta, at pages 11 and 12 of the hearing transcript, and to counsel for the Board's staff, at page 29 of the transcript. The Board included clause 5 to ensure that customers would continue to receive electric service under the terms of then existing contracts, essentially unaffected, either materially or in quality of service, by the transfer from TransAlta to Edmonton Power.

On 14 May 1984, a hearing was convened in Edmonton, Alberta, to consider Application 840136 which was filed by Esso Petroleum Canada, A Division of Imperial Oil Limited (Esso). The application sought an amendment to Approval HE 8208 on the basis that Edmonton Power was not abiding by the condition set out in clause 5.

The matters dealt with at the 14 May 1984 hearing are set out in the Board's Decision Report D 84-14. As discussed in the report, the Board found that the spirit and intent of clause 5 of Approval HE 8208 were not being satisifed with respect to service to the Esso tank farm. The Board expressed the view that the preferred method of resolving the matter would be for Edmonton Power, Esso, and TransAlta to negotiate a solution. It allowed the three parties 3 months to reach an agreement, failing which the Board would be prepared to reopen the hearing.

In a letter to the Board, dated 28 September 1984, Edmonton Power advised that an agreement had not been reached, and requested that the Board hear the matter.

The hearing of Application 840136 was reopened in Calgary, Alberta, on 18 December 1984, with Board Members, G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting. The participants at the reopened hearing are listed in the following table.

2 ISSUES

The Board considers the issue to be a solution that would allow Edmonton Power to meet the spirit and intent of clause 5 of Approval HE 8208, as it applies to electric service to the Esso tank farm.

3 DECISION

The Board finds that the proposal of Edmonton Power, generally as set forth in paragraph 3(a) of its submission dated 26 November 1984 (Exhibit 15), would satisfy the spirit and intent of clause 5 of Approval HE 8208. Paragraph 3(a) proposed restoring the tank farm load to TransAlta retroactive to 1 August 1982 and continuing into 1989, and refunding the billing revenue to date to Esso.

The Board believes that the Esso tank farm should be served according to the terms of the existing contract for a reasonable length of time. Accordingly, it directs

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Esso Petroleum Canada, A Division of Imperial Oil Limited (Esso) D. G. Hart, Q.C.	J. F. Zupancic, P.Eng. G. T. Belbin, P.Eng.
The City of Edmonton (Edmonton Power) M. McAvoy	B. Hiron
TransAlta Utilities Corporation (TransAlta) E. J. McCoy	W. Janke, P.Eng.
Energy Resources Conservation Board staff C.J.C. Page	

that the tank farm be served by TransAlta until 31 December 1989, or such other date as all three parties agree to, at which time service shall be transferred to Edmonton Power.

The Board prefers that Edmonton Power, Esso, and TransAlta work out the minor details required to put this solution in place, but suggests that modifications to the existing physical plant should be avoided or kept to a minimum to avoid added costs to customers of both utilities.

The Board notes the comments of Mr. Janke that a resolution could be reached with regard to any changes required to the Modified Unit Power Agreement between Edmonton Power and TransAlta. The Board prefers that the two parties again negotiate any required changes, as was done when the agreement was reached following the service area transfer.

ISSUED at Calgary, Alberta, on 11 January 1985.

ENERGY RESOURCES CONSERVATION BOARD

GJDeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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LOCAL INTERVENERS' COSTS RESPECTING THE 240-kV TRANSMISSION LINE FOR THE LANGDON SUBSTATION TO ANDERSON SUBSTATION

Decision D 84-15

1 INTRODUCTION

Applications 830440 and 830618 by TransAlta Utilities Corporation (TransAlta) and Alberta Power Limited are for the necessary approvals to construct and operate a 240-kV transmission line from the Langdon substation to the Anderson substation. The applications were considered at a hearing which commenced 6 March 1984 in Strathmore and was adjourned 14 March 1984.

At the commencement of the hearing, a number of interveners requested that the Board adjourn the proceeding and direct that the applicants investigate alternative routes for the proposed line. The applicants opposed the requested adjournment. The Board denied the request but stated that "If at a later time…the Board determines it needs more detailed information regarding alternative routes…the Board may at that time adjourn the proceeding…". On 14 March during the 5th day of the hearing and at a stage where only the TransAlta evidence had been heard and cross-examined, the interveners again requested an adjournment and a direction that the applicant be required to investigate alternative routes and come back to the Board with an alternative. The request was again opposed by the applicants. The Board, because it was of the view that "…further and more detailed information is needed with respect to possible alternatives" adjourned the hearing sine die. The applicants are expected to bring additional evidence before the Board, and depending on whether the applications are amended, the hearing would either be re-scheduled or re-opened.

2 THE COST CLAIMS

Applications for local intervener costs have been filed by a number of interveners, all of whom had intervened with respect to the TransAlta application. The claims were sent to TransAlta for its review, and the interveners subsequently responded in writing to the written TransAlta comments. Appendix I is a summary of those making claims and the amounts requested.

The claimants generally contend that it is appropriate for the Board to award costs even though the hearing was not completed because it has been adjourned sine die and there are uncertainties as to when it will resume. Several suggest that much of the costs incurred by interveners resulted because their initial request for adjournment had been denied, in part due to opposition from the applicants. Two of the interveners request, in the event that their applications for cost award are denied, that they be granted an advance of costs to cover expenses to date. They contend that the circumstances in this particular case are exceptional in that the present adjournment could be for a lengthy period, and also because the adjournment is to require the applicants to obtain additional information and not to allow interveners to prepare their cases.

The interveners, in response to detailed questions raised by TransAlta respecting the cost claims, contend that all costs incurred to date were legitimate and necessary to properly participate in the hearing. TransAlta responded to the claims by suggesting that it would be improper for the Board to make an award of costs at this stage of the proceeding because the hearing had not been completed as is contemplated in the regulations before costs would be awarded. It argued that a presentation of the interveners submissions was necessary before the Board could assess whether the costs claimed are reasonable having regard for the proceeding, and whether the interventions were conducted economically.

TransAlta also contends that an advance should not be given unless exceptional and special circumstances exist, there should be a demonstrated need for the advance, and the advance should not cover the full amount of the claims. It further questions whether certain groups that made presentations are all "local interveners" as defined in the Act, whether some individuals were represented by more than one group thus duplicating cost claims, and whether all of the work carried out was related to the proceeding. TransAlta also challenges some of the details where different work logs of different people do not coincide in terms of meetings and attendance.

3 VIEWS OF THE BOARD

The Board generally agrees with TransAlta that it would be difficult to make proper cost awards at the current stage where the hearing has been adjourned but the interveners' submissions have not been presented. For this reason, and because the Board expects that the matter will continue in one manner or another despite the adjournment on a sine die basis, it is not prepared at this time to make an award of local intervener costs. Consequently, it has not considered in detail the arguments by the involved parties respecting the validity of each component of the claims.

At the same time, the Board is impressed by the arguments of the interveners that they should not be required to carry the costs of the interventions to date, particularly because the time frame involved could be lengthy and the adjournment is not to allow interveners to prepare their cases. The Board believes the circumstances in this case are unique in that they involve an initial request for adjournment, a denial of that request, a relatively lengthy partial proceeding, a further request for adjournment, the granting of that request, and a delay which will likely be four or more months. It agrees with certain of the interveners that these circumstances are exceptional and special, and believes there is a need for advances because the interveners would otherwise have to carry the costs for their interventions to date for a considerably longer period than was visualized when the regulations were established. The Board thus concludes there is justification for providing advances to the local interveners. However, in keeping with its normal approach in terms of advances, an advance would not cover all of the expenditures to date by the interveners.

Although the Board has not reviewed the cost claims in detail, it is satisfied that all of the intervener groups on whose behalf claims have been made, are at least partially made up of "local interveners" as defined for cost purposes. The Board recognizes there may be some duplication of claims but does not believe it can determine that issue until the interveners have presented their submission. Also, the claims appear to be generally reasonable. Having the above mentioned matters in mind and believing that it should not attempt at this stage to settle the differences in opinions respecting details of the claims, the Board has decided, with one exception, to provide advances to the interveners for 65 per cent of the total amounts claimed as shown in Appendix I. The exception is with respect to the claim on behalf of Mary T. Turner which is substantially greater than the others and includes a fee from a consulting firm respecting preparation of a report yet to be submitted to the hearing. TransAlta questioned in its submission on the cost claims, whether the cost for the report directly and necessarily related to the intervention. The Board recognizes that there is a greater degree of uncertainty with respect to this particular claim than the others and for this reason, will provide an advance for 50 per cent of the Turner claim. Additionally the Board will not advance payment for the claim for costs associated with preparation of the cost claim. As is provided for in the legislation and regulations, if in the final analysis the amount of any of the advances made is greater than the ultimate award of costs, or a party is determined not to be a local intervener, the party receiving the advance will be required to pay back the difference. When the amount of the advance is less than the final award, TransAlta will be ordered to pay the amount advanced by the Board, to the Board and the difference to the intervener.

4 DECISION

The Board will pay advances to the interveners with respect to Application 830440 in the following amounts:

Claimant	Amount of Advance
Mary T. Turner as submitted by Messrs. Warren, Raymaker & Stewart	$24,500.00
West Wheatland Surface Rights Group as submitted by Messrs. Beaumont Proctor	$8,400.00
Mr. & Mrs. Eugene William Helfrich as submitted by Messrs. Sinclair McGeough Lilburn	$3,700.00
Strathmore Area Pilots and Airport Operators Group ("Papp Claim") as submitted by Messrs. Milne Vicars & Papp	$3,400.00
Audrey Crisp as submitted by Messrs. Ballem, McDill & MacInnes	$5,600.00
Raymond and Nina Newell, Harwood Farms Ltd. and **William H. Barnett** as submitted by Messrs. Burnett, Duckworth & Palmer	$11,700.00
Svend D. Jensen	$400.00
David Thomas as submitted by Messrs. Peterson Anderson & Shields	$2,200.00
Kathleen Ann Moody as submitted by Messrs. Peterson Anderson & Shields	$1,800.00
Homeowners of the Hamlet of Cheadle as submitted by Messrs. Peterson Anderson & Shields	$4,200.00

Dated at Calgary, Alberta, on 8 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

C. J. Goodman

C. J. Goodman
Board Member

R G Evans

R. G. Evans
Acting Board Member

APPENDIX I

INTERVENER COST CLAIMS

Claimants	Solicitor's Fees & Disbursements	Honoraria for Attendance at Hearing	Disbursements	Total
Mary T. Turner as submitted by Messrs. Warren, Raymaker & Stewart	$15,821.45 2,800.00**	$600.00	$251.10 $32,415.73* + 496.50**	$49,088.28
West Wheatland Surface Rights Group as submitted by Messrs. Beaumont Proctor	$12,742.04		$246.80	$12,988.84
Mr. & Mrs. Eugene William Helfrich as submitted by Messrs. Sinclair McGeough Lilburn	$6,113.13			$6,113.13
Strathmore Area Pilots and Airport Operators Group as submitted by Messrs. Milne Vicars & Papp	$4,180.00	$1,200.00	$200.00	$5,580.00
Audrey Crisp as submitted by Messrs. Ballen McDill & MacInnes	$8,187.24	$700.00	$418.68	$9,305.92
Raymond and Nina Newell, Harwood Farms Ltd. and **William H. Barnett** as submitted by Messrs. Burnett, Duckworth & Palmer	$18,089.39	$1,350.00		$19,439.39
Svend D. Jensen		$500.00	$240.06	$740.06
David Thomas as submitted by Messrs. Peterson Anderson & Shields	$2,824.00	$900.00		$3,724.00
Kathleen Ann Moody as submitted by Messrs. Peterson Anderson & Shields	$3,069.06			$3,069.06
Homeowners of Hamlet of Cheadle as submitted by Messrs. Peterson Anderson & Shields	$5,741.41	$1,300.00		$7,041.41

* To TES Research Consultants Ltd. for preparation of a report.
** Claim for costs incurred to prepare the cost claims.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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ESSO RESOURCES CANADA LIMITED APPLICATION TO PROCEED WITH PHASES III AND IV OF THE COLD LAKE PROJECT

Decision D 84-16
Application 840296

1 APPLICATION

Esso Resources Canada Limited (Esso) has applied pursuant to the provisions of Approval 3950 to proceed with Phases III and IV of the Cold Lake Project. Approval 3950, issued in September 1983, approved the eventual development of 25 400 cubic metres per day (m^3/d) of crude bitumen production from the Esso Cold Lake Project Development Area as shown on Figure 1. Also, it permitted the immediate production of 3000 m^3/d of crude bitumen under Phases I and II.

Clause 2 of Approval 3950 explicitly requires that the operator make application before commencing subsequent phases and anticipates that they would be allowed to proceed upon the operator receiving approval respecting details pertaining to each subsequent phase. The current application, filed on 26 March 1984, is for approval of details of Phases III and IV.

A summary of the details for Phases III and IV follows:

- Crude bitumen production rate of 3000 m^3/d from 5.75 sections of land shown on attached Figure 2.
- Fresh water make-up requirement can be met within the existing water withdrawal licence provisions.
- Additional deep well disposal requirement of 200 m^3/d and additional sulphur dioxide (SO_2) emissions of 1.5 tonnes/day (t/d).
- Deferral of upgrading and therefore an additional diluent requirement of 1500 m^3/d.
- Construction to begin as early as July 1984 with plant start-up in early 1986.
- On-site peak construction workforce of 440 persons, 80 permanent operations jobs, and 40 on-going construction jobs.
- Modest socio-economic impacts that can be accommodated within the current regional infrastructure and service programs.
- Expansion of programs with the Native people as initiated in Phases I and II.
- Continued access to employment opportunities and programs for local communities.

The Energy Resources Conservation Board (Board) has reviewed the application respecting these details and is satisfied that it conforms with the provisions of previous decisions set out in detail in ERCB Report 79-E, ERCB Decision 81-C, and ERCB Decision D 83-21. The Board is also generally satisfied that the application conforms with the particular provisions for phasing the project as set out in Approval 3950.

Esso held a number of meetings with business, public interest, and Native groups and civic leaders in the area, who generally indicated support for the Phase III and IV project. There were no substantial concerns raised by these groups, except for a submission filed by the Cold Lake Indian Band (CLIB) which stated conditional approval of the project. The Board is satisfied that the conditions proposed by the CLIB could be accommodated by a suitable amendment of Approval 3950.

The Board therefore would be prepared to grant the application, provided there are no key issues remaining. In the following section, the Board has addressed specific details to establish whether the application for implementation of Phases III and IV as proposed by Esso should be granted.

2 SPECIFIC DETAILS

The Board has reviewed the details respecting conservation, technical merit, fuel gas requirements, upgrading, and the availability of diluent. In each of these respects, the Board concludes that implementation of Phases III and IV as now proposed by Esso is sound and orderly, and meets the general provisions of the approval. The Board's position is therefore essentially the same as that reported in ERCB Decision D 83-21 and the Board sees no need to review these matters further.

Given the above conclusions, the remaining concerns that the Board must address are:

- Net changes to biophysical environmental impacts (not including fresh water make-up).
- The use of Cold Lake as a source of fresh water make-up for Phases III and IV.
- Changes to the socio-economic impacts.

3 CHANGES TO BIOPHYSICAL ENVIRONMENTAL IMPACTS

Changes to the environmental impacts (excluding fresh water use which is addressed separately) include air emissions, deep well disposal, sewage disposal, and land disturbance.

SO_2 emissions would increase by 1.5 t/d once Phases III and IV reached the design production rate of 3000 m^3/d of crude bitumen. This emission level is similar to that for Phases I and II. While the Board is generally satisfied that these additional air emissions are relatively minor, it notes that Esso has designed an ambient air monitoring program in compliance with the Clean Air Act that includes periodic air monitoring on the Cold Lake Indian Reserve No. 149B in response to a request for that monitoring by CLIB. In addition, the Board continues to be prepared to arrange for portable air monitoring equipment at the request of the CLIB or others to ensure that air quality problems do not materialize and to confirm the adequacy of Esso's monitoring program. As well, the ERCB Bonnyville Office is available to receive and co-ordinate rapid follow-up on any odour or air emission complaints.

Under normal operating conditions, the incremental deep well disposal volumes to the Cambrian formation would be in the order of 100 to 200 m^3/d of regenerant wastes. Produced water would be disposed of only as a result of a treatment plant upset or imbalance in the supply and demand of produced water. The Board notes that the overall deep well disposal program is subject to clauses 25 and 26 of Approval 3950 with appropriate monitoring being a subject of the ERCB deep well disposal approval.

Although Esso originally proposed to discharge sewage lagoon effluent and segregate clean water runoff from the site of the Phases III and IV facilities to Jackfish Creek, it now plans to recycle both streams into the produced water treatment plant. This would eliminate any discharge to Jackfish Creek. The Board regards this as an improvement that will reduce the environmental impact of Phases III and IV. The Board therefore supports the proposal and concludes it is no longer an environmental issue.

The Board notes that a Development and Reclamation Plan will be filed with Alberta Environment as called for by clause 18 of Approval 3950. This comprehensive plan, in which ERCB staff participates in the review leading up to the terms of approval, should ensure sound long-range land reclamation planning. Respecting near-term land disturbance impact, the Board has reviewed the site development plan filed with the application and is satisfied that it will maintain surface disturbance at a minimal practical level similar to that of Phases I and II. In addition, the Board will require the operator to provide to the ERCB field office at Bonnyville on a quarterly basis, the as-built site plan of drilling and construction programs as those proceed. This will permit ERCB staff to maintain continual surveillance of site operations from the Bonnyville Office. Any problems that may arise respecting land disturbance, liquid spills, or similar impacts can thereby be readily brought to the attention of the ERCB staff, which in turn would ensure that corrective measures were implemented promptly.

4 USE OF COLD LAKE AS A SOURCE OF FRESH WATER MAKE-UP

Esso proposes that the expansion to Phases III and IV can be accommodated within the existing water withdrawal licence provisions for Cold Lake and Ethel Lake as set out in Interim Licence 12298 issued by Alberta Environment under the Water Resources Act. The overall water management plan includes:

- scheduling peak start-up requirements of Phases III and IV at a time when peak start-up requirements of Phases I and II have been largely satisfied;
- recycling water that is produced from the Leming and May-Ethel experimental schemes and is currently disposed of in deep wells into the Phases I and II water treatment plant;
- reallocating the experimental scheme recycled water to Phases I and II and allowing fresh water from Cold Lake under the current licence limit to be available for the requirements of Phases III and IV.

On the basis of the above program, the Board concludes that the use of Cold Lake as the source of fresh water make-up for Phases III and IV insofar as it can be achieved within the current water withdrawal licence should not present any immediate concerns. To that extent, the Board is in agreement with the use of Cold Lake for Phases III and IV.

Clause 24(2) of Approval 3950 states: "No source or method of providing additional fresh make-up water to the project shall be proceeded with by the Operator without the express written authorization of the Board and the Department of the Environment."

Although the Esso plan for Phases III and IV appears acceptable from the viewpoint of fresh water use, nonetheless the question of that use deserves further comment at this time. The Board wishes to reaffirm its position as set out on page 10 of ERCB Decision D 83-21:

> "The Board would expect future applications for water use for subsequent phases to be in accordance with a long-term water plan for the area, but notes that in its earlier decision, ERCB Report 79-E, it denied use of the lake for the full scale project and has not seen evidence that might change its view."

While the Board notes that the combined water use requirements for Phases I, II, III, and IV can now be accommodated without modification to Interim Licence 12298, the Board believes that the moving ahead of Esso's phased project under Approval 3950, as well as consideration of potential fresh water requirements for additional projects now being considered in this area, could lead to a need for an accelerated program of development of the longer-term plan. The Board intends to arrange for discussion of this general question with Alberta Environment in the near future.

5 CHANGES TO SOCIO-ECONOMIC IMPACTS

The Phases III and IV workforce requirements include a peak of 440 construction workers and 120 on-going operations and construction workers. This is less than the workforce for Phases I and II due to increased construction efficiency. Esso also stated that incremental infrastructure requirements would be modest because of the surplus of existing infrastructure in the Cold Lake region.

The Board believes that any expansion in the area of job opportunities would provide both direct and indirect benefits to the local economy in particular, and to Alberta and Canada as well. The Board notes that local residents and municipalities are invited to refer particular problems respecting the timely provision of required community services and facilities directly to the Advisory Committee on Heavy Oil and Oil Sands Developments[1]. This would ensure direct access to government when prompt review and decision-making is needed.

Esso's efforts for Phases I and II with respect to local employment and business opportunities, and Native training, employment, and business opportunities, have included: public information programs, in-house and on-the-job training programs, agreements with contractors for local hiring, and liaison with other agencies such as Canada Employment and Immigration Commission, Native Outreach, Community Advisory Committee, Blue Quills School, and Lakeland College. Esso has committed to continue these programs into Phases III and IV.

The Board is generally satisfied that the local programs implemented by Esso for Phases I and II have been beneficial and generally meet the Board's call for such programs. Although the Board accepts that continuation of these initiatives in Phases III and IV would probably meet with agreement from all local groups, it nevertheless would arrange special meetings to review any such matters if requested to do so.

6 DECISION

The Board, having reviewed the details of Phases III and IV and having regard for the potential impacts and public benefits, has decided to approve Phases III and IV as applied for.

DATED at Calgary, Alberta, on 14 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

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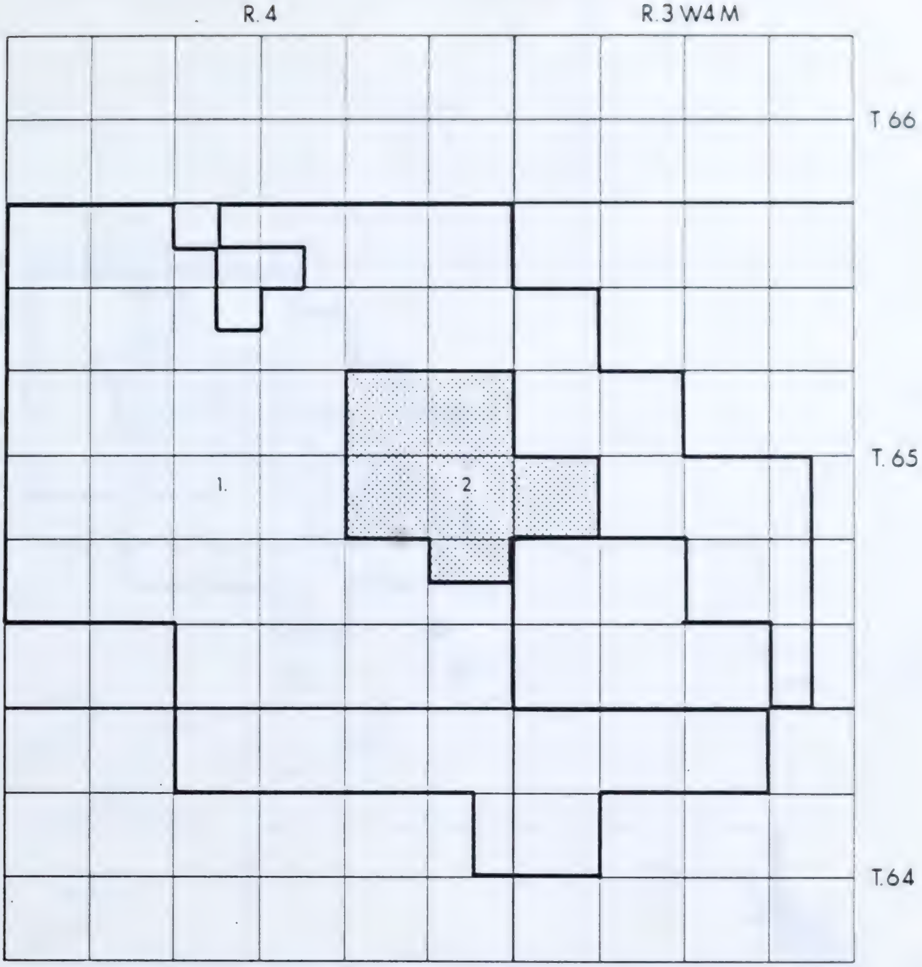
[1] Advisory Committee on Heavy Oil and Oil Sands Development; Attention Mr. J. E. (Bud) Miller; Edmonton 427-4864.



1. COLD LAKE PROJECT DEVELOPMENT AREA
2. PHASES I AND II DEVELOPMENT AREA

FIGURE 1 EXISTING COLD LAKE PROJECT DEVELOPMENT AREA

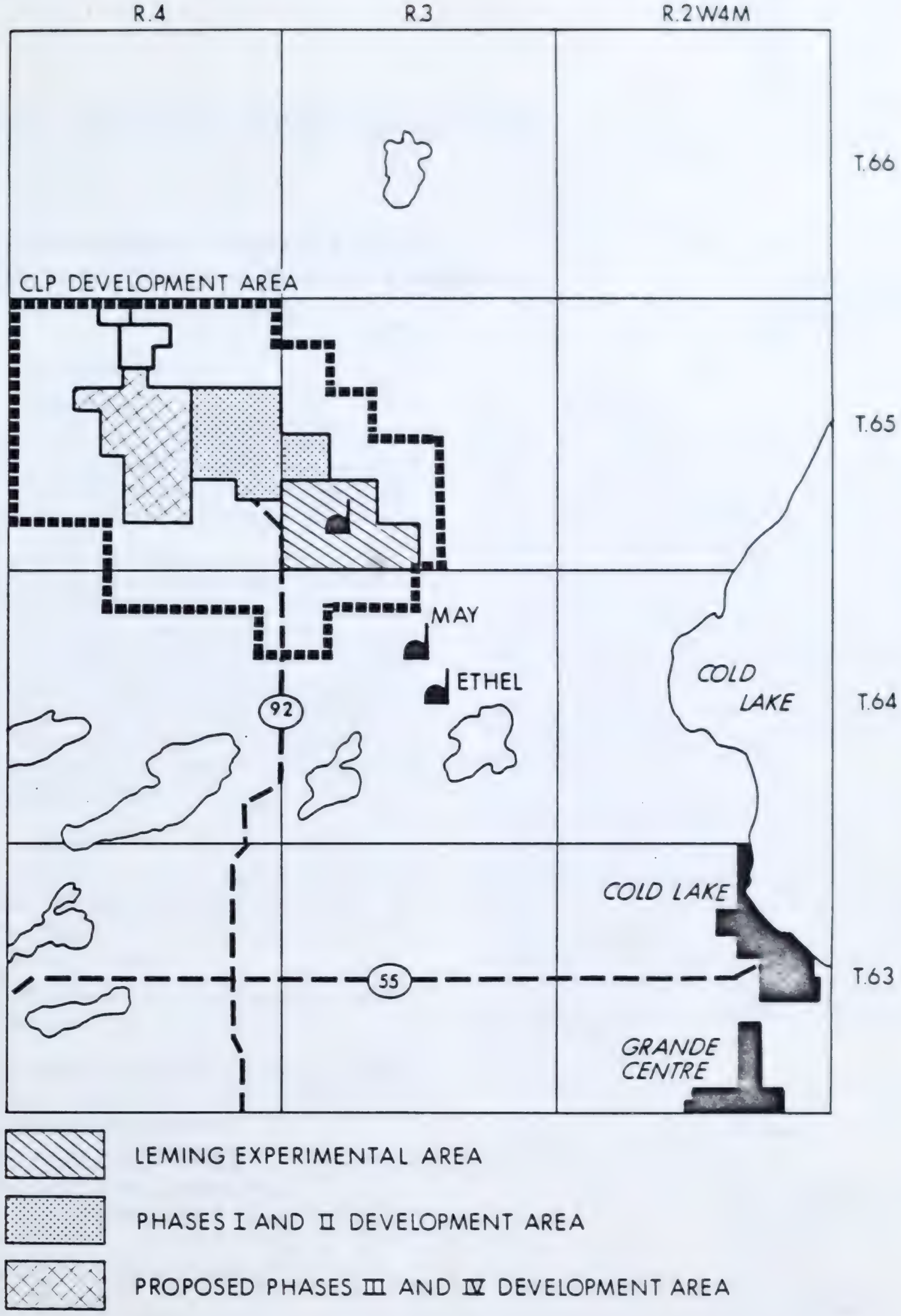


FIGURE 2 GENERAL LOCATION MAP
(ADAPTED FROM ESSO RESOURCES CANADA LIMITED)

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

NORTHWESTERN UTILITIES LIMITED PIPELINE UPGRADING AT ROAD CROSSINGS COUNTY OF LAC ST. ANNE

Decision D 84-17
Application 840193

1 INTRODUCTION

1.1 Application

Northwestern Utilities Limited (NUL) applied, under section 41 of the Pipeline Act, for approval to upgrade NUL's 323-millimetre outside diameter Swan Hills gas transmission pipeline at road crossings in the County of Lac St. Anne.

In order to meet current design code requirements, NUL proposed to install split casings on twenty-four road crossings and to substitute heavy-wall pipe on two other crossings between section 29 in township 57, range 3, west of the 5th meridian and section 25 in township 57, range 1, west of the 5th meridian. At the hearing, NUL amended its application to install casing instead of heavy-wall pipe at one of the other road crossings.

1.2 Hearing

A public hearing of the application was held in Edmonton, Alberta, on 25 May 1984 with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and R. G. Evans, P.Eng., sitting.

Those who appeared at the hearing are shown in the following table.

1.3 Background

NUL's gas transmission pipeline was installed in 1963 and transports gas from Swan Hills to Edmonton. The licensed Maximum Operating Pressure (MOP) would create a stress level of 69 per cent of specified minimum yield strength (SMYS) of the pipe material. At the time of construction, the code in effect was the American Standards Association B31.8-1958, and a requirement of this code was the restriction of stress level for uncased road crossings in Class 1 locations to 60 per cent of SMYS or less. This code was later replaced by Canadian Standards Association Code CSA Z184, which specifies the same design standard for such locations.

In 1982, NUL approached the County for permission to construct the cased crossings. After lengthy negotiations with the County, NUL was unable to obtain the County's approval required under section 40 of the Pipeline Act to upgrade the road crossings, except under conditions which NUL deemed unacceptable. NUL therefore applied to the Board for an approval under section 41 of the Act on the basis that it could not reasonably obtain approval from the County.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Northwestern Utilities Limited (NUL) W. A. Andreassen	S. A. Weiderick, P.Eng. G. K. Munk, P.Eng. L. G. Wattie
County of Lac St. Anne (County) M. C. Welsh	A. Barr A. R. Koberstein R. Johnston
Energy Resources Conservation Board staff H. R. Hansford A. Cassley, P.Eng. I. M. Cameron, P.Eng.	

2 ISSUES

The Board considers the issues respecting the application to be:

- the purpose and necessity of upgrading the pipeline,
- the reasonableness of the conditions imposed by the County on the granting of approval to case the road crossings, and
- the need for conditions to be imposed on any approval granted by the Board to accommodate the County's concerns.

3 VIEWS OF THE PARTICIPANTS

3.1 NUL

NUL stated that the pipeline has been in service for some 20 years without any failures at road crossings or any evidence of deterioration. A cathodic protection system has been maintained and monitored on a regular basis.

NUL noted that the pipeline was presently operating at pressures creating a stress level of less than 60 per cent of SMYS and within code requirements. The pipeline had never operated at the MOP and NUL believed that operating pressures would remain at present levels for some time. However, the possibility existed that, in the future, the pipeline would be required to operate at a pressure of about 5750 kilopascals, creating a stress level of 62 per cent of SMYS in the pipe.

NUL believed that the licensed MOP should not be reduced to that which would produce a stress level of 60 per cent of SMYS as it would only postpone the present problem. If that were done, any future increase in MOP would require the pipeline to be taken out of service and pressure tested. As the pipeline is a major supply line to the Edmonton area, any shut-down would cause a serious disruption of service.

NUL stated that there is no absolute advantage in upgrading the line over leaving the pipeline in its present undisturbed condition. It said that the casing work could potentially encounter new problems such as the possibility of construction damage, increased loads due to weakened soil support around the pipe, and corrosion primarily due to water leakage into the casing annulus. However, NUL believed that the upgrading could be done safely and would provide an extra measure of insurance.

NUL claimed that installing casings using open cut ditching would result in lower construction costs and the ability to keep the pipeline in service during construction. Boring road crossings, installing new heavy-wall pipe, and connecting the new section to the existing pipeline would cost about three times that of installing casings and require hot tap connections to the new pipe. Thus the installation of protective casings in an open cut would be much preferable to boring road crossings and installing new pipe.

NUL had undertaken to absorb all costs associated with the casing work. NUL believed that the County was being unreasonable in withholding its approval to do the casing work, and stated that the County was making demands of NUL which had no bearing on the proposed work.

In response to a request made by the County at the hearing, NUL stated that it would provide the County with a 14-day written notice of the commencement of casing work at each location and, if requested within the 14 days, to construct the pipeline casing of a road crossing in two sections of one-half of the road width, leaving the other half of the road open for traffic flow. NUL also undertook to provide the County with an estimate of the time required to install casings at each crossing, and to the extent possible to do the work during July and August when interference with school buses would be least.

3.2 County

The County did not challenge the purpose or necessity of pipeline upgrading. The County recognized the need for NUL to work on its pipelines from time to time. It stated that it would not require boring of road crossings and would approve the method of open cut ditching. The County was concerned about the lack of notification from NUL with respect to past work done in the County and the subsequent traffic interruptions, particularly school bus routing. It was also concerned about soil subsidence resulting from road crossing work and the County's liability for road conditions prior to repairs completed by NUL.

At the hearing, the County requested that certain conditions be imposed on NUL prior to approval being granted to proceed with the casing work. The County requested NUL to provide:

- a 14-day written notification prior to the commencement of work being done,

- a time estimate of disruption to traffic, and
- upon request within the 14-day notice period, the casing of a road crossing in two sections in order to avoid traffic diversion.

The County also proposed to undertake the repair of soil subsidence and to bill NUL at its cost rates for repair on an annual basis.

4 VIEWS OF THE BOARD

The Board accepts that the operating condition of the pipeline has remained virtually unchanged from the time of original construction with no signs of structural deterioration. The Board observes that interfering with a pipeline which has reached a level of stress equilibrium after a long period of operation has the potential to introduce new problems. However, the Board recognizes NUL's obligation to meet the design code requirement effective at the time of construction. Although the pipeline has been operating within code requirements for some 20 years, the Board acknowledges that the lowering of licensed MOP to meet the code requirement would only be a temporary solution and is therefore undesirable.

The Board notes that the County's proposed conditions of approval presented at the hearing did not contain the one condition that NUL earlier found unacceptable. The Board agrees that these conditions are reasonable and NUL agreed to accept them.

5 DECISION

The Board is prepared to approve the casing of the pipeline at 25 road crossings and the boring and installation of heavier wall pipe at 1 other crossing, subject to NUL meeting the following conditions:

- NUL to provide a 14-day written notice to the County of construction prior to any casing work being done,
- NUL to provide an estimate to the County of the length of time of traffic disruption at a road crossing during installation of pipeline casing, and
- when requested by the County within the 14-day notice period, casing work to be done in half road widths in order to avoid complete traffic disruption.

ISSUED at Calgary, Alberta, on 25 June 1984.

ENERGY RESOURCES CONSERVATION BOARD

V E Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

R G Evans

R. G. Evans, P.Eng.
Acting Board Member

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ZAHAVA HANEN AND RUMSEY RANCHES' REQUEST FOR LOCAL INTERVENERS' COSTS RE: ESSO QUIRK CREEK GAS PLANT

Decision D 84-18
Application 830698

1 INTRODUCTION

In 1981, the Board held public hearings to consider the application of Esso Resources Canada Limited (Esso) to process Moose and Whiskey gas at its Quirk Creek plant. It also considered applications for pipelines to connect the Moose and Whiskey reserves to the plant. The Board found that the proposed pipelines were not compatible with other land uses in the Elbow River Valley and consequently denied the application. In its report, the Board indicated that it would be prepared to consider the processing of Whiskey reserves at Quirk Creek, but since it had denied the Moose pipeline facilities, it was not prepared to grant the application to process those reserves at the Quirk Creek plant.

In 1983, the Board heard an application from Shell Canada Resources Limited (Shell) for a reconsideration of the Board's decision to deny the Moose pipeline facilities based upon new information respecting the safety and compatibility of the proposed facilities, and subsequently approved construction of the facilities.

Later in 1983, Esso submitted Application 830698 for a reconsideration or review of the Board's decision respecting the Quirk Creek plant. Its application was based on the Board's decision approving construction of the pipeline facility to supply Moose and Whiskey gas to the plant.

The Board set the application down for a hearing on 24 October 1983. Zahava Hanen and Rumsey Ranches (Hanen) filed an intervention to the application which requested the Board to require the applicant to file additional information relating to current plant operations, sulphur emission surveys, sulphur block details, and environmental and corrosion monitoring data before proceeding with consideration of the application. The information requests were discussed at the opening to the hearing and a Procedural Ruling was issued on 27 October 1983. Based upon the submissions made at the hearing, the panel identified the issues that would be relevant to the hearing which was rescheduled to commence on 16 January 1984. Those issues were:

(a) The sulphur level that should apply to the Quirk Creek plant when Moose reserves are processed.

(b) The impact on environment and on the public of processing Moose reserves at the Quirk Creek plant.

(c) The impact on resource recovery of processing Moose reserves at the Quirk Creek plant.

Hanen filed an intervention at the hearing dealing with the minimization of sulphur dioxide emissions, which included a report by Goar, Arrington & Associates, Inc. entitled ''Report on Alberta Energy Resources Conservation Board, Application No. 830698, re Esso Resources Canada Limited's Quirk Creek Gas Processing Plant'', and a report by Foster Research Ltd. entitled ''Forecast Prices for Natural Gas, Natural Gas Liquids and Sulphur at the Quirk Creek Gas Plant and for Natural Gas Liquids at the Jumping Pound Gas Plant 1984-2005''.

Application 830698 by Hanen for local interveners' costs includes the following:

Goar, Arrington & Associates, Inc.	$ 70,055.88
Foster Research Ltd.	19,009.93
Counsel	46,989.71
TOTAL	$136,055.52

The Board forwarded the application to Esso for comment on 18 April 1984. Esso responded on 24 May and contended that:

''1 The claim for local interveners costs by Zahava Hanen and Rumsey Ranches ought to be dismissed since it is not related to a proper local intervention but rather an intervention of general public concern without reference to actual or potential effects of plant emissions on the Hanen lands.

2 In the alternative, the award should be substantially reduced on account of its unreasonable dimensions when measured against the applicable legislative and regulatory

> criteria, as well as the history, pertaining to awards of local interveners costs since enactment of the enabling legislation in 1978.''

Hanen responded on 5 June 1984, contending that ''the costs . . . . . are related to an intervention . . . . . by a person who has an interest in land that 'is or may be directly and adversely affected' . . . . . and are reasonable and are directly and necessarily related to the preparation and presentation of what was . . . . . a highly effective, technical, site specific, reasonable and successful intervention''.

Hanen also requested that the Board grant an advance of $50,000.00 toward the ultimate award for costs.

The Board has carefully reviewed the submissions by both Esso and Hanen respecting the costs application.

2 LOCAL INTERVENER STATUS

In Decision D 83-8 the Board found that Zahava Hanen and Rumsey Ranches were local interveners under section 31(1) of the Energy Resources Conservation Act. Esso agreed that Hanen is a local intervener with respect to the Quirk Creek plant. The Board continues to believe that Hanen is a local intervener and that the concentration of her intervention on issue (a) with some reference to issue (b) was appropriate for a local intervener to address.

3 WAS IT APPROPRIATE FOR HANEN TO REQUEST GOAR, ARRINGTON AND FOSTER RESEARCH TO PREPARE THEIR REPORTS?

Esso contended that it was not reasonable for Hanen to arrange for the Goar, Arrington and Foster Research reports to be prepared. Hanen takes the opposite position. The Board has reviewed the arguments put forward by each of the parties.

The facts are that Esso applied for the previously approved sulphur recovery rate of 95.5 per cent to be increased to 96.5 per cent with the processing of the Moose and Whiskey reserves. At the 1981 hearing, Esso contended that a recovery rate in excess of 96.5 per cent would require installation of tail gas clean-up facilities and that tail gas clean-up was not warranted because not only was it uneconomic, but also the sulphur emissions from the plant over the past 10 years of operations had not had a deleterious environmental effect.

At the 1981 hearing, Hanen argued that the recovery rate should be established at 99.9 per cent because of the perceived impacts of emissions on her lands and because of general environmental principles which required the use of best available technology rather than best practical technology. She contended that the guidelines set forth in IL 80-24 were inadequate and should be amended. The Board, in Decision D 82-12 and in Report 82-D, concluded that best available technology was not the required basis under the Oil and Gas Conservation Act and that IL 80-24 appeared reasonable. Because the application for facilities to transport Moose and Whiskey gas to Quirk Creek was denied, the Board did not, in Decision D 82-12, deal with the question of the sulphur recovery rate that should apply in the event that Moose and Whiskey gas were processed at the Quirk Creek plant. In its Procedural Ruling on 27 October 1983, the panel indicated that one of the issues relevant to the consideration of Esso's application was the applied-for sulphur recovery rate.

The evidence in the 1981 hearing clearly demonstrated that Hanen was of the view that her lands ''may be directly and adversely affected'' by emissions from the Quirk Creek plant. The Board had found, after considering the submission of the participants on 24 October 1983, that the sulphur recovery rate was an issue with respect to the Esso application. The Board had previously concluded that IL 80-24, the existing ERCB-Alberta Environment sulphur recovery guidelines, should continue to be the basis for considering the sulphur recovery rate that should apply to the Quirk Creek plant. The questions then related to:

- whether the applied-for rate of 96.5 per cent was consistent with IL 80-24; and if not,
- whether tail gas clean-up facilities would be feasible, at what cost, and in the circumstances would it be justified?

In the Board's view, these questions are complex and technically difficult to answer. Although Esso put forward an expert technical and environmental panel to address these questions, the documentary evidence provided by Esso with respect to each question was rather limited. Esso, in the 1981 hearing, had declined a request by the Board to file sufficient economic data to permit broad economic evaluations. As well, the introduction into the plant of a separate gas marketer (Shell) with its own contractual objectives as well as the differing perceptions of gas sales opportunities seemed to cause a reticence on Esso's part to unequivocally address the question of anticipated plant loadings.

Therefore, recognizing Hanen's concern for the impacts that emissions from the plant might have on her lands and on her health, and the complex nature of the issues involved, the Board believes that it was reasonable for her to engage the services of consultants to provide expert assistance in evaluating the technical feasibility, practical problems, and comparative economics involved with improved sulphur recovery methods.

4 WERE THE GOAR, ARRINGTON AND FOSTER RESEARCH STUDIES CARRIED OUT IN A REASONABLE MANNER?

Esso contended that the consultants' costs were ''out of line'', which in the case of Goar, Arrington, referred specifically to ''an excessive amount of time'' as well as other contributing factors. In the case of the Foster study, Esso contended that there is ''general public availability of price forecasts''.

Hanen disputed all of these submissions, arguing that each of the studies was carried out in an efficient manner and disagreed with the contention that price forecasts were generally available.

The Board has carefully considered these conflicting arguments. With respect to those sections of the Goar, Arrington report that dealt with sulphur recovery matters, the Board is satisfied that with the exception of sections 2, 4, and most of 9, which were ruled-out of consideration at the start of the hearing, the depth of treatment was not unreasonable. Moreover, because of the limited information provided by Esso, it was reasonable, in the Board's view, for Goar, Arrington to prepare the somewhat detailed comparative economic evaluations included in the report. With respect to the question of whether or not the time required by Goar, Arrington to complete their work was excessive, the Board finds it difficult to judge the matter with precision. A review of the time sheets does not provide a breakdown between different phases of the work. Considering their need to fully appraise themselves of the gas plant operation, to evaluate the technical and economic feasibility of sulphur recovery options, and to be present throughout the hearing, the Board is generally satisfied but agrees that the time required appears somewhat excessive. With respect to Esso's contention that the Foster study on prices was redundant because of the availability of other forecasts in the public domain, the Board does not agree. In order for Hanen to test the validity of the contention that tail gas clean-up facilites were not economic at the Quirk Creek plant, it was necessary to make detailed forecasts based upon prices related to Quirk Creek operations, and it was appropriate to decide that such forecasts should have behind them the weight of experts in order that they be accepted and persuasive.

While the Board agrees that it was reasonable for Hanen to engage Goar, Arrington to review sulphur recovery matters, it believes it was unreasonable for her to have arranged for a review of plant operational matters as identified in sections 2, 4, and most of 9 of the report. This matter was clearly addressed by the Board on 27 October 1983 in its Procedural Ruling. The Board has considered how the costs should be adjusted in order to reflect both the expenditures associated with sections 2, 4, and most of 9 of the Goar, Arrington report and the somewhat excessive time spent on preparing the other sections.The Board believes that the costs of both counsel and the consultants should be adjusted. Sections 2, 4, and 9 comprise roughly 20 per cent of the report. The Board does not expect that those sections would have required that large a portion of the total report time. The conclusion that somewhat excessive time was required for other sections cannot be translated in any rigorous manner. All things considered, the Board has concluded that a reduction of $20,000.00 is reasonable. It amounts to a 17 per cent reduction of the total costs of Goar, Arrington and counsel.

5 DECISION

Having regard for the foregoing, the Board directs that Zahava Hanen and Rumsey Ranches be awarded $116,055.52 local interveners' costs pursuant to section 31 of the Energy Resources Conservation Act, the costs to be paid by Esso Resources Canada Limited.

DATED at Calgary, Alberta, on 16 July 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R. G. Evans, P.Eng.
Acting Board Member

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BRAZEAU RIVER NISKU CARBONATE BANK OPTIMUM DEPLETION INQUIRY

AMOCO CANADA PETROLEUM COMPANY LTD.

Memorandum of Decision
Proceeding 840350
Application 840147
Decision D 84-19
Applications 840286 and 840287

1 INTRODUCTION

The Carbonate Bank of the Nisku Formation in the Brazeau River Field contains a gas condensate fluid having potential for enhancement of liquid hydrocarbon recovery by dry gas cycling. There is a high degree of interest in gas cycling among the well operators, but differing views on pool configuration, reservoir transmissibility, and reservoir fluid properties have led to different concepts as to when and how cycling might be developed. The Energy Resources Conservation Board (Board) convened common proceedings to consider a general inquiry into the depletion of the Carbonate Bank and to hear specific applications by Amoco Canada Petroleum Company Ltd. (Amoco) for a cycling scheme in the Carbonate Bank and for two pipelines to permit production of a well in the Carbonate Bank.

1.1 Proceeding 840350

The Board initiated an inquiry into the optimum depletion strategy for the recovery of hydrocarbons from gas reservoirs in the Nisku Carbonate Bank in the Brazeau River Field. Interested parties were requested to make submissions pertaining to the optimum depletion strategy of the Carbonate Bank reserves.

1.2 Application 840147

Amoco applied pursuant to section 26 of the Oil and Gas Conservation Act for approval of a scheme for the cycling of gas in a portion of the Brazeau River Nisku Carbonate Bank. The scheme proposes the injection of dry gas into the well located at 10-2-48-12 W5M (10-2) and wet gas production from the wells located at 7-34-47-12 W5M (7-34), 7-10-48-12 W5M (7-10), and 13-12-48-12 W5M (13-12).

1.3 Applications 840286 and 840287

Amoco applied pursuant to Part 4 of the Pipelines Act for permits to construct approximately 3.2 kilometres (km) of 168.3-millimetre (mm) outside diameter sour gas pipeline from the 7-10 well to a gathering system connection in 7-34-47-12 W5M (Application 840286) and approximately 3.2 km of 60.3-mm outside diameter fuel gas pipeline from an existing fuel gas pipeline in 7-34-47-12 W5M to the 7-10 well (Application 840287). The pipelines would be required to transport sour gas to the Hudson's Bay Oil and Gas Company Limited (HBOG) processing facilities located at 6-10-47-14 W5M (HBOG 6-10 plant).

2 THE INQUIRY AND HEARING

The inquiry and hearing was opened on 25 June 1984 in Calgary, Alberta, before a division of the Board comprised of V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and J. A. Bray, P.Eng., Acting Board Member.

THOSE WHO APPEARED AT THE INQUIRY AND HEARING

Principals and Representatives
(Abbreviations used in Report)

Amoco Canada Petroleum Company Ltd. (Amoco)
  A. G. Kruse
  S. E. Lipton

Dome Petroleum Limited (Dome)
  F. Saville
  R. Neufeld

Petro-Canada Resources (Petro-Canada)
  D. O. Sabey, Q.C.
  B. K. O'Ferrall

Texaco Canada Resources Ltd. (Texaco)
  R. Blumell

Her Majesty the Queen in the Right of Alberta (Crown)
  T. Bossenberry

Energy Resources Conservation Board staff
  M. J. Bruni

3 REQUEST FOR ADJOURNMENT

Prior to the presentation of evidence, Dome requested that the Board adjourn the inquiry and hearing until 1 December 1984. This request was based on an agreement between Dome, HBOG, Petro-Canada, Amoco, and Texaco for a testing program for the Carbonate Bank area which would not be completed until the end of November. The testing program, as presented by Dome, would involve nine Carbonate Bank wells as illustrated in the attachment.

3.1 Petro-Canada's Views

Petro-Canada supported the request for adjournment provided it did not put Dome in a position of advantage by allowing the 7-34 well to produce beyond what would be the case if the inquiry proceeded. Under the proposed testing program, the 7-34 well is to be produced during July and August, with the possibility of further production commencing in October or later. Petro-Canada stated that the adjournment and testing program would be acceptable if production from the 7-34 well was restricted to 25.4 million cubic metres (0.9 billion cubic feet) or three months of production during the period up to 1 December 1984. The three-month restriction would allow for one month of production each from the wells located at 6-29-47-11 W5M (6-29) and 3-20-48-12 W5M (3-20) prior to 1 December 1984. Petro-Canada added that if the 7-34 well was initially produced for two months, it would be agreeable to a third month of production in December. It stated that the 3-20 well was already below its anticipated dew point, and the restriction on 7-34 production was intended to minimize the need for injected make-up gas to alleviate retrograde condensate losses.

3.2 Dome's Views

Dome contended that there was no merit in conducting the inquiry or the hearing of the Amoco cycling application until the results of the proposed testing program were available and could be used to help determine the optimum depletion strategy. It suggested that adjournment to 1 December 1984 would allow test results to be available to aid in the formulation of an optimum depletion plan strategy. Dome added that this date would still allow for winter construction and scheme implementation in 1985.

With respect to restrictions on production of the 7-34 well, Dome stated that it will abide by the previously imposed condition not to produce below the dew point pressure, but that it does not agree with the further restrictions proposed by Petro-Canada.

3.3 Texaco's Views

Texaco agreed to the proposed testing program and supported adjournment of the inquiry and hearing.

3.4 Amoco's Views

Amoco, although in agreement with the testing proposal, did not support the request for adjournment. Amoco argued that adjournment would presuppose that its application for cycling is premature and without merit at this time. It further argued that there would be little to be gained by adjournment as there is a lack of overall agreement regarding development of this area, and it does not expect this to change in the future. Amoco was confident that it could present evidence to show that its cycling scheme is an appropriate depletion strategy. It added that if the inquiry and hearing were adjourned until December, the time necessary for construction and implementation would preclude a mid 1985 start-up.

3.5 Board Staffs' Views

Board staff indicated that further reservoir information would be desirable for the inquiry to proceed in an efficient manner. Although in general agreement with the proposed testing program, Board staff did have some queries and concerns regarding the details. The staff suggested that the most expedient method of resolving these concerns would be through meeting with the participants outside the framework of the inquiry. The staff further requested that it be updated regularly as testing progresses. Based on the proposed testing program and these conditions, Board staff supported adjournment.

3.6 Board's Views

The Board considered both the proposed testing program and the request for adjournment. The Board notes that all participants are in general agreement that more pressure and production information is required from the Carbonate Bank. The Board agrees in principle with the proposed testing program and expects the information obtainable by the testing program will be beneficial in determining the optimum depletion strategy. In considering Amoco's request for continuation of the proceedings, the Board believes that the inquiry should be held before the hearing of any applications concerning cycling. The Board therefore decided that the inquiry and hearing should be adjourned pending results of the testing program.

Regarding the application of restrictions on production of the 7-34 well, the Board considered the uncertainties of the area's reserves, fluid properties, and reservoir communication. It concluded that further restrictions may be required in addition to not producing below the dew point pressure, because of the possibility of communication of the 7-34 well with other areas having higher dew point pressures.

The Board believes that the planned initial stage of production of the 7-34 well during July and August is reasonable, but that any further production should be considered in the light of results of the first stage. Accordingly, total production during this initial stage is to be restricted to a total of 17.46 million cubic metres, corresponding to the proposed average rate of 281.7 thousand cubic metres per day for two months.

The testing program subsequently calls for the well to be shut in for at least a month during which pressure build-up would be measured and then the effect of producing the well analysed. Thereafter, Dome will be required to apply to the Board justifying any further primary production. The other operators may wish to respond to any such request from Dome, and hence a prompt exchange and analysis of reservoir data will be expected of all parties.

4 PIPELINE APPLICATIONS

4.1 Amoco's Views

Amoco requested that, although the inquiry and hearing of the cycling application had been adjourned, the Board still consider hearing the pipeline applications.

4.2 Participants' Views

The pipeline applications were not opposed by Dome, Petro-Canada, or Texaco. The Crown stated that it had some questions of clarification regarding the pipelines but that it would be prepared to discuss these matters with Amoco outside of the hearing.

4.3 Board's Views

The Board notes that the pipelines would be needed to transport gas produced from the 7-10 well to the HBOG 6-10 plant, and that there were no objections to the pipelines. The Board is prepared to approve the pipelines subject to Amoco satisfying the Crown's concerns and subject to receipt of the approval of the Minister of the Environment.

5 SUMMARY AND DECISION

The Board considers the proposed testing program to be beneficial to the inquiry and hearing regarding optimum depletion of the Brazeau River Carbonate Bank. To allow for this additional information, the inquiry and hearing has been adjourned to 27 November 1984. Public notice will be given respecting the new details of the inquiry and hearing.

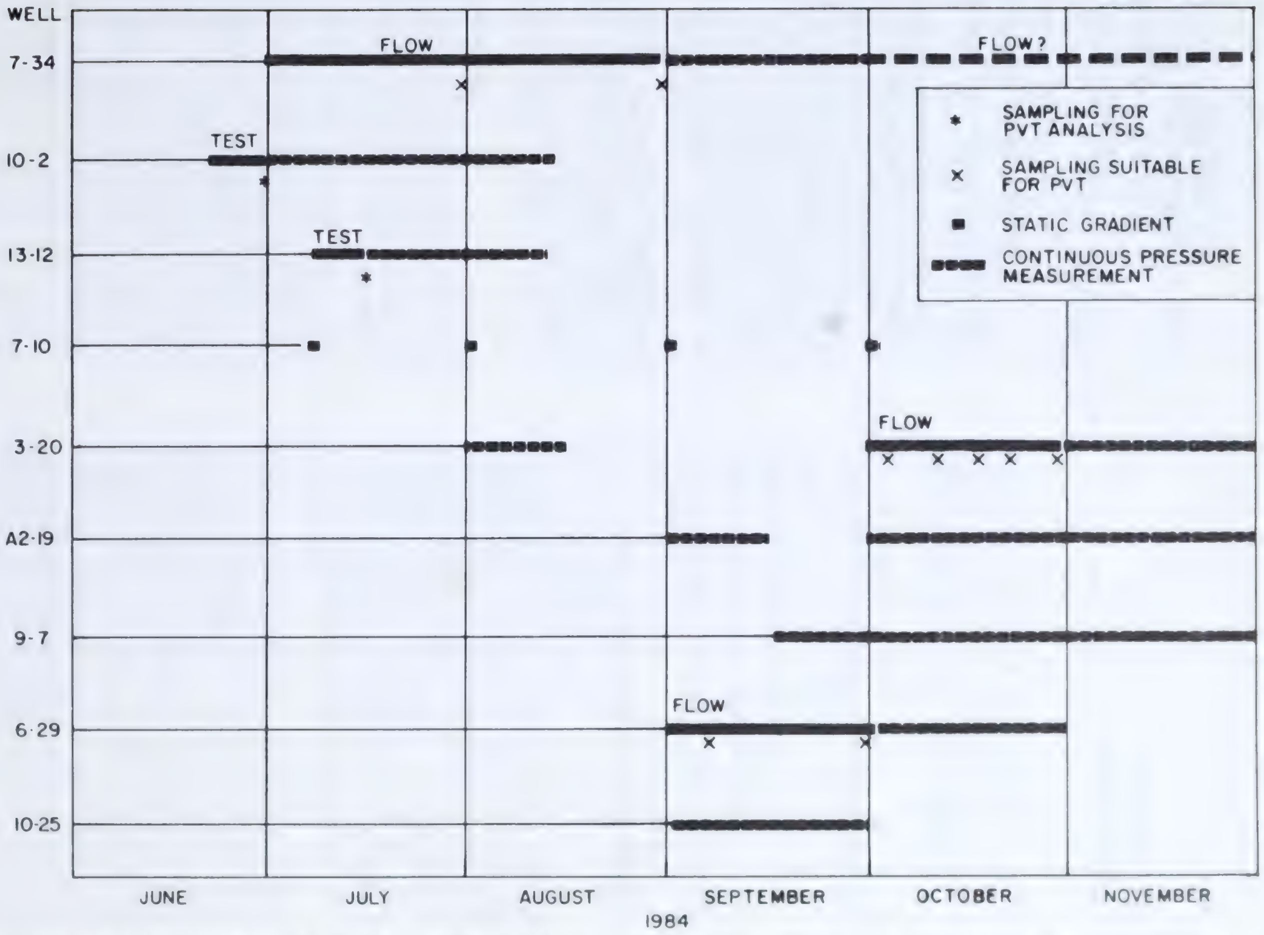
Initial test production from the 7-34 well will be limited to 17.46 million cubic metres. Further production will be considered in the light of results to that point.

The Board will issue the necessary permits for pipeline Applications 840286 and 840287 following receipt of the approval of the Minister of the Environment.

DATED at Calgary, Alberta, on 18 July 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman



BRAZEAU RIVER CARBONATE BANK. Flow and pressure monitoring program.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BANKENO RESOURCES LTD. APPLICATION FOR APPROVAL OF A GAS PROCESSING PLANT MORINVILLE FIELD

Decision D 84-20
Application 840290

1 INTRODUCTION

1.1 The Application and Hearing

Bankeno Resources Ltd. (Bankeno) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct and operate a sour gas processing plant at an existing well site located in Lsd 11-15-55-25 W4M (11-15), in the Morinville Field. The plant facilities would be designed to process a maximum of 70.4 thousand cubic metres per day (70.4×10^3 m^3/d) of raw sour gas from which 68.8×10^3 m^3 of sales gas would be recovered. A maximum of 0.52 tonnes per day (t/d) of sulphur dioxide (SO_2)[1] would be flared from a stack 23 metres (m) in height.

The application was considered at a public hearing in Morinville, Alberta, on 8 August 1984, with V. E. Bohme, P.Eng., E. J. Morin, P.Eng., and E. R. Brushett, P.Eng., sitting. Those who appeared at the hearing are listed in the following table.

1.2 Interventions

The South Morinville Clean Air Association intervened on behalf of residents and landowners in the area. Two members included in this group, Mr. and Mrs. Boddez and Mrs. Pasay, also presented submissions at the hearing on their own behalf.

The interveners expressed concerns regarding the proposed plant's emissions, degradation of the area's air quality, expected sulphur deposition on local agricultural lands, safety, and the effect on the value of their property. The Pasays indicated concerns that the site proposed was too close to an area of high population density and that approval may establish a trend for numerous smaller sour gas plants. The attached figure indicates the location of the interveners' land near the proposed 11-15 site.

The Crown intervened for purposes of cross-examination only. The Municipal District of Sturgeon No. 90 intervened to audit the hearing only and did not actively participate in the proceedings.

2 ISSUES

The Board considers the issues regarding the application to be:

- the need for the proposed facility,
- proposed location and alternatives, and
- environmental impact and other interveners' concerns.

3 THE NEED FOR THE PROPOSED FACILITY

3.1 Applicant's Views

Bankeno stated the 11-15 well had been drilled in 1976 but the well remained shut in until it had obtained a market for the gas. Bankeno needed the gas to meet the contract it now has with Norcen Energy Resources Limited (Norcen) which requires Norcen to purchase gas produced from the 11-15 well on a best efforts basis only, to augment quantities of gas already being taken from other gas producers in the area.

The 11-15 well's initial gas analysis indicated the raw gas contained 80 parts per million (ppm) hydrogen sulphide (0.008 per cent H_2S) which Norcen was able to accept at its sweet gas processing plant in section 26-54-25 W4M by blending the slightly sour gas with sweet gas. The 11-15 well started producing in September 1983; however, after six weeks of production and a subsequent analysis, the gas was found to contain 2700 ppm H_2S (0.27 per cent H_2S). This concentration was unacceptable for Norcen's processing facilities and the 11-15 well was shut in. Bankeno stated that before it could resume producing the well it would have to add facilities to sweeten the raw gas. It therefore proposed to add an inlet separator, a skid-mounted amine sweetening unit, a utility trailer, buried waste

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[1] Sulphur dioxide is a compound formed from equal weights of sulphur and oxygen. Therefore, the estimated daily emissions can be described as either 0.52 tonnes per day of sulphur dioxide or 0.26 tonnes per day of sulphur.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Bankeno Resources Ltd. (Bankeno) A. L. McLarty	M. Stuart,[2] P.Eng. B. Stobo,[2] P.Eng. M. Petovello, C.E.T. of LanMark Petroleum Services Ltd. M. Schroeder of Western Research, Division of Bow Valley Services Ltd. C. Boyce of Western Oilfield Environmental Services Ltd.
South Morinville Clean Air Association (the Interveners) P. Sharko	P. Sharko A. Boddez S. Boddez
D. and I. Pasay I. Pasay	I. Pasay
A. and S. Boddez A. Boddez S. Boddez	A. Boddez S. Boddez
Municipal District of Sturgeon No. 90 C. Crozier	
Her Majesty the Queen in Right of Alberta (the Crown) C. S. Liu, P.Eng. W. Diepeveen	
Energy Resources Conservation Board staff R. Hansford M. Semchuck, C.E.T. M. A. Francis, C.E.T.	

[2] Both Mr. Stuart and Mr. Stobo are employees of Merland Explorations Limited. Merland operates Bankeno's property on a management fee basis.

water and liquid hydrocarbon storage tanks, and an acid gas flare stack 23 m in height to its existing gas well facilities.

3.2 Interveners' Views

The Pasays objected to the concept of a small gas plant not recovering sulphur. They contended that approval of the scheme may initiate a "trend" to smaller gas processing facilities. The combined effect of emissions from numerous small plants in an area would be more detrimental than the effect of emissions from a single strategically located plant which could recover sulphur.

4 PROPOSED LOCATION AND ALTERNATIVES

4.1 Applicant's Views

Bankeno submitted that it had evaluated the feasibility of utilizing existing gas sweetening facilities at either the Oakland Petroleums Limited plant situated approximately 11 kilometres (km) southeast at Lsd 13-12-54-25 W4M or the Amoco Canada Petroleum Company Ltd. plant located some 14 km southwest at Lsd 14-36-53-26 W4M. It claimed a pipeline to either facility would encounter water bodies, other pipelines, and a major highway along its route. The cost to build a pipeline would be between $600 000 and $900 000 compared to approximately $300 000 for its proposed processing facility. It concluded that the cost to pipeline production from 11-15 to either existing facility would be uneconomic.

Bankeno also stated that it had investigated several alternative gas sweetening processes but found they either had operational problems or were cost prohibitive for this application. In particular, it contended that an iron sponge process would require two 3-m by 9-m vessels at an estimated combined cost ranging between $700 000 and $800 000 not including the cost to change out the spent iron sponge every 20 days.

With regard to using the proposed plant for other wells, Bankeno said because its proposed plant would be portable, it would be preferable to move the plant to another well site after the 11-15 well had been depleted rather than to pipeline gas production to this site.

In response to the interveners' questions regarding the effect that the proposed facility might have on the value of land near to the plant, Bankeno referred to a previous study of selling prices for lands around existing sour gas plants. The applicant claimed that this study showed that the presence of gas plants in an area did not affect the selling price of nearby properties.

4.2 Interveners' Views

The interveners said they reside directly downwind of the proposed plant in a farming community. They stated that presently there are about 17 children under the age of 12 who reside within 1.6 km of the facility. The interveners believed that the proposed plant would be too close to their residences and claimed that exposure to the plant emissions over an extended period of time would be hazardous to health. Mrs. Pasay contended that the cost to pipeline the raw gas to an alternative processing site with sulphur recovery facilities would be money well spent to preserve the area's present air quality and maintain the area residents' existing quality of life.

The likelihood of property values dropping due to the plant's presence was also a concern to the area residents. Mr. and Mrs. Boddez submitted that their property would be worth less than true market value due to the proximity of the gas plant. They stated they had contacted a real estate agent in their area and received advice to that effect. They indicated that they were not aware of any studies that suggested this might not be the case.

5 ENVIRONMENTAL IMPACT AND OTHER INTERVENERS' CONCERNS

5.1 Applicant's Views

Bankeno submitted that it had utilized Alberta Environment's flare stack design model to evaluate the levels of SO_2 emission from the acid gas flare stack. It emphasized it would blend sufficient fuel gas with the acid gas to ensure complete combustion of the acid gas. This would also maintain the maximum anticipated ground level concentrations of SO_2 below 0.17 ppm on an hourly average, which is the maximum permissible level set out in Alberta's ambient air quality standards. It expected that actual ground level concentrations would be one-tenth of the permitted 0.17 ppm maximum rate.

Bankeno stated that as an additional safety factor, it used worst case conditions in determining the maximum ground level concentration for SO_2 of 0.005 ppm from the emergency flare. It had assumed an H_2S concentration of 0.27 per cent in the natural gas and adverse meteorlogical conditions for plume dispersal. Bankeno noted that shut-downs and start-ups would occur approximately once per month, and the emergency flare would be used during those operations. In the event of some operational failure at the plant, Bankeno said the plant would be shut down automatically and only natural gas in the various plant vessels would be flared through the emergency flare. This depressuring of the plant through the flare would take approximately 5 minutes.

With respect to air monitoring, the applicant affirmed it would undertake a 1-month air monitoring survey to determine ambient H_2S and SO_2 concentrations along with wind speed and wind direction prior to commencing plant operations. Bankeno also proposed to monitor atmospheric emissions of H_2S and SO_2 with sulphation cylinders which it would locate downwind of the proposed plant.

Bankeno stated that it would remove H_2S from any gas to be vented to the atmosphere. As a result, the glycol dehydration unit would not cause H_2S odour episodes similar to those experienced by the interveners during previous production operations at the well. It said it would install thermocouples and ignition systems on the flares, interfaced with the plant shutdown system, to prevent venting unburned H_2S to the atmosphere through the flare stacks. It also said that, in the event that complete combustion of H_2S

was not obtained at the flare tip, it would be prepared to install a device to provide greater assurance of complete combustion of the plant's acid gas. A liquid knock-out drum would be installed in the plant's flare system to eliminate any smoke. Odours from drain tanks and the water storage tank would not be noticeable beyond the lease boundary. Bankeno submitted that in the event of odour complaints, it would investigate and eliminate the odour and endeavour to rectify the situation as quickly as possible.

Bankeno predicted that the acid-gas flare would produce a noise level of less than 25 decibels (dBA) at 400 m from the base of the flare stack and this would be equivalent to a soft whisper at a distance of 5 m. During emergency flaring, sound levels estimated to be 35 to 40 dBA at 400 m from the flare stack, would be experienced for about 30 seconds. The applicant contended this would be equivalent to the sound level associated with noise inside a public library. It submitted that the only other sources of noise would be two electric motors which would be housed in an acoustically lined building.

Regarding the interveners' concerns about possible deterioration of the area's soils due to the proposed plant's emissions, Bankeno submitted that soils in the area are categorized as Class 1 and 2 soils having variable soil chemistry. Based on soil surveys previously carried out in the general area, Bankeno indicated that in upwind areas (north and northwest of the plant) soil pH readings were 5.5 to 6.0 while downwind areas (south and southeast of the 11-15 site) had pH values of 7.3 to 7.4. The applicant said that it expected the area's soil to have moderate to good buffering capacity and believed there should be little or no increase in the acidity of the area's soils due to the minor amount of sulphur deposition from the plant.

Bankeno affirmed that it had not carried out any soil sampling and analysis but contended that soil monitoring in an area could produce extremely variable results. The applicant alleged that due to variance in soil parent material, agricultural practices, and climatic conditions, information gained through soil sampling and analysis would be of limited value in determining the effect of sulphur deposition.

Bankeno conducted a study of the plant's effect on wet sulphur deposition within a 16-km radius of the 11-15 site and compared it with the Federal Government's recently established guidelines which specify a maximum acceptable loading of 6.7 kilograms per hectare per year (kg/ha/yr) of wet sulphur. Bankeno estimated that total wet sulphur deposition for the area around the 11-15 site would be in the order of 5.2 kg/ha/yr[3], of which 3.0 kg/ha/yr was attributed to background deposition, and 2.2 kg/ha/yr would be the predicted maximum resulting from 11-15 plant's emissions. Bankeno emphasized that this maximum would occur in a small area and since it was less than the level the Federal Government had established as a maximum to ensure protection for all but the most sensitive aquatic environments, Bankeno anticipated no impact from sulphur being deposited on the area surrounding its proposed facility.

Regarding safety, Bankeno stated it would install and utilize monitors to detect fire, combustible gas, flame failure on the acid gas and emergency flare stack, and low instrument voltage. It would have a radio alarm system to contact the plant operator who would be available to respond to plant upsets on a 24-hour basis. It stated that a company phone number, to report complaints or convey concerns, would be posted on the site and given to nearby residents. In the event that Bankeno anticipated an unusual amount of flaring or was going to commence plant start-up, it would advise local people of its upcoming plans to help alleviate resident concerns.

Bankeno claimed the visibility of the processing equipment would be minimal. It said the flare from the acid gas flare stack would be no brighter than a street lamp, the two flare stacks would have the same visual impact as telephone poles or T.V. antennas, and the process buildings would be similar to a granary in the field.

Bankeno submitted that its first priority after project approval would be to meet with area residents and local authorities to formulate a contingency plan to handle emergency situations.

5.2 Interveners' Views

The interveners stated that, although the expected effects of the emissions from the plant are deemed to be minimal, their experiences with odourous emissions from the Lodgepole blowout and the previous operation of Bankeno's 11-15 well indicate that the emissions cause health problems. Mrs. Sharko claimed that area residents experienced eye irritation and nausea, and her son required medical attention for asthma attacks when odours from the 11-15 well were apparent. Prior to the operation of Bankeno's facility and during the Lodgepole blowout, exposure to emissions caused the Pasays to experience enough discomfort to consult a doctor. The interveners believed that existing standards are not adequate to ensure preservation of the environment. Additionally, they stated that long-term effects on human and animal health, soil, water, and vegetation, resulting from continuous exposure to low concentrations of SO_2 emissions, were not yet determined. They termed the proposed plant's emissions, incremental air pollution and said it could cause insidious changes and environmental damage and should not be overlooked because it is not visible or widespread. Mrs. Pasay contended that Bankeno's proposed gas processing facility no longer represents progress when it affects many people adversely, as has been the experience of the interveners with the 11-15 gas well installation to date. The interveners stated that in the event emissions do present a health problem, it would be uneconomic and not feasible for them to relocate their homes or farming operations. Mrs. Pasay confirmed in her intervention that soils in the area were Class 1 and 2 but indicated that the district agriculturalist had not had a soil test with a pH reading of 7.0 or greater for the area and suggested that Bankeno's evidence of pH readings of 7.3 to 7.4 in the area of the proposed site is in error. In reference to the expected sulphur deposition, the interveners indicated that they would prefer to make their own choice as to whether or not to apply sulphur on their land.

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[3] For comparison, 5.0 kg/ha/yr is about 4.5 pounds per acre per year.

The interveners requested that, in the event the location for the processing facility is approved, the permit be delayed until a review is completed by the ERCB of IL 80-24[4] as it pertains to small gas plant operations and until consideration is given to the possibility of requiring sulphur recovery by small sour gas processing facilities in the province. They further requested that the permit be conditional upon the following:

- monitoring instruments be set up in the vicinity as proposed by the applicant,
- spot monitors be located near the interveners' properties,
- access be provided to all monitoring reports,
- soil tests be done before plant start-up and at yearly intervals,
- the interveners be informed by letter of any application for plant expansion or increased emissions, and
- the applicant be required to comply with any revised stricter regulations for sulphur recovery or reduction of emissions should such legislation be established.

The interveners stated they would be willing to participate in a committee to meet with the applicant to discuss their concerns about the continuing operation of the plant in their community.

6 BOARD'S VIEWS

The Board recognizes that the applicant has, subject to appropriate regulatory controls, the right to produce the gas from the 11-15 well for its benefit and that of the province as a whole. The applicant has negotiated a contract to sell the gas and now requires the proposed gas plant in order to continue producing the gas to fulfill its contract. The Board also notes that the applicant had considered alternative gas processing facilities in the area to sweeten the gas and determined that the costs to pipeline the gas to other existing facilities would substantially exceed the cost of the proposed sweetening unit. Alternative gas processing methods and sulphur recovery processes for this project were also evaluated by the applicant. The Board notes that the applicant found these processing alternatives to be insufficiently proven technically, or too costly for this project. It further notes that the proposed facility is designed for the purposes of processing gas at this well site only and that the unit would be portable.

The Board acknowledges the concerns expressed by the interveners regarding odorous emissions from the proposed plant, especially since odours were experienced by the area residents when the well was initially produced. Additionally, the Board understands the interveners' heightened awareness of the effects of sour gas emissions as a result of their experience during the Lodgepole blowout. It believes that all precautions necessary must be taken to prevent a recurrence of odorous emissions from the proposed facility. Consequently, the Board has reviewed the design of the processing facility and finds that all possible sources of fugitive odours have been considered except the proposed storage tanks. The Board will therefore require that the vents from all the storage tanks be tied into a vapour recovery system. The Board is satisfied that with careful operation, the plant should not be a source of odours.

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[4] Sulphur Recovery Guidelines — Gas Processing Operations — Requirements Set For Sulphur Recovery at New or Expanding Alberta Sour Gas Plants. Informational Letter IL 80-24, ERCB, Calgary.

With respect to SO_2 emissions, the Board notes that the 11-15 facility has been designed to operate in accordance with current regulations and standards and that the applicant proposes to establish a baseline for air quality in the vicinity before the plant commences operating.

The Board has considered the evidence given by Bankeno to support its view that the proposed plant emissions would not have an effect on the acidity of soils around the proposed plant site. Given the small amount of sulphur deposition, the Board does not believe that soil tests would be definitive in evaluating the effect of the plant on soils in the area, since changes in the soils could occur for many reasons and not be identified as solely due to plant emissions.

With respect to the interveners' request for deferring plant approval because current guidelines are under review, the Board does not believe that delaying the approval of this plant is warranted. The Board is obligated to decide an application before it under existing legislation and changes to legislation may take many months to complete. Part of the legislation review process is to determine whether any new regulations and standards should be retroactive. Similarly, any proposed plant expansion which would result in increased emissions would be reviewed as a new application to the Board.

The Board notes that the applicant proposes to meet with the area residents to formulate an emergency response plan, to continue discussions with interveners about their concerns, and to advise them of any anticipated disruptions to the plant operations. The Board notes that the interveners are also amenable to continuing dialogue with the applicant.

7 DECISION

The Board concludes that the proposed plant is necessary to produce and market gas from Bankeno's 11-15 well, and that the plant design and proposed operation would be in accordance with existing regulations and standards.

The Board will issue its approval for the proposed plant subject to approval of the Minister of Environment with respect to environmental matters and also subject to the following additional conditions:

- that all vents from all storage tanks be tied into a vapour recovery system,
- that a baseline air quality study be carried out for a minimum of one month and until the plant is operational, and
- that the applicant meets with the interveners to establish a communications committee for the purpose of exchanging information with area residents as agreed.

DATED at Calgary, Alberta, on 14 September 1984.

ENERGY RESOURCES CONSERVATION BOARD

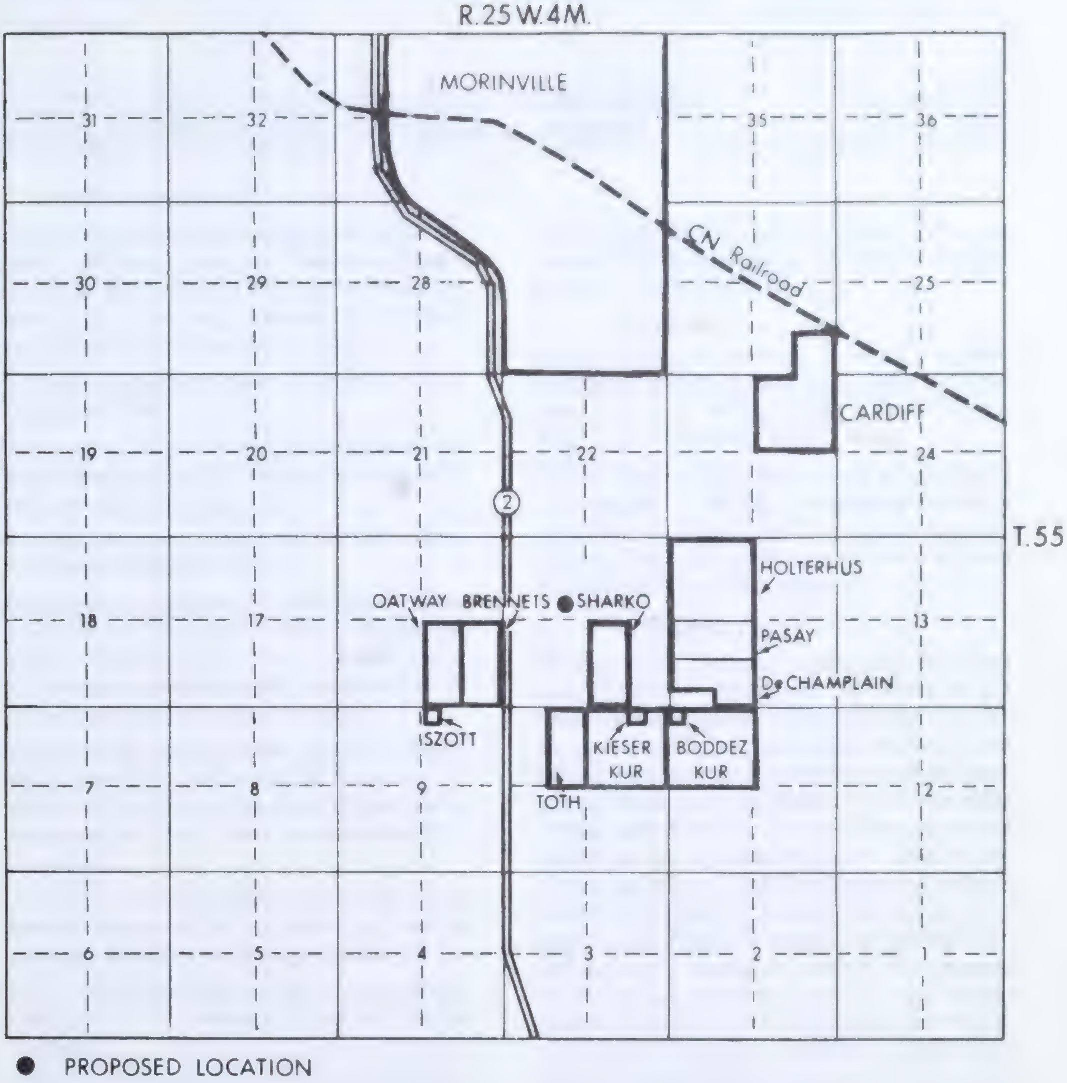
Bohme

V. E. Bohme, P.Eng.
Board Member

E. J. Morin, P.Eng.
Acting Board Member

E R Brushett

E. R. Brushett, P.Eng.
Acting Board Member



MORINVILLE GAS PROCESSING PLANT LOCATION AND AREA

UNI
GOVT DOCS.
DEC 1 2 1984

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SOCIÉTÉ QUÉBÉCOISE D'INITIATIVES PÉTROLIÈRES APPLICATION TO AMEND GAS REMOVAL PERMIT

Decision D 84-21
Application 840564

1 APPLICATION

Société québécoise d'initiatives pétrolières (SOQUIP) applied to the Energy Resources Conservation Board (ERCB), pursuant to section ll of the Gas Resources Preservation Act (the Act), to amend Gas Removal Permit SQ 83-1. The amendment would:

- extend the permit term from 31 October 1997 to 31 October 1999;
- increase the total volume of gas to be removed from Alberta by 5.108 billion cubic metres (10^9 m^3) to 6.108×10^9 m^3;
- increase the annual volume by 340.545 million (10^6) m^3 to 408.075×10^6 m^3;
- increase the maximum daily volume by 933 thousand (10^3) m^3 to 1.118×10^6 m^3 during the period 1 November 1984 to 31 October 1997, and authorize a maximum daily volume of 933×10^3 m^3 thereafter to 31 October 1999;
- provide for the carry forward of gas not removed during a particular annual period during any of the four following annual periods which are within the term of the permit, subject to maximum daily limitations;
- provide for delivery of up to 110 per cent of the specified maximum daily volumes in order to overcome temporary operating problems; and
- name 15 additional fields, pools, and areas from which gas may be obtained for removal from the province.

SOQUIP, a corporation owned by the Province of Quebec, is currently removing gas from Alberta under Gas Removal Permit SQ 83-1, which authorizes a total removal of 1.0×10^9 m^3 of gas during the period 27 July 1983 to 31 October 1997. The gas is transported in Alberta by NOVA, AN ALBERTA CORPORATION (NOVA) to the Alberta-Saskatchewan border where it is sold to Gaz Inter-Cite Quebec (GICQ), a gas distributor in which SOQUIP and Inter-City Gas Corporation each own a 49 per cent interest. The gas is then transported through the TransCanada PipeLines Limited (TransCanada) and Trans Quebec & Maritimes Pipelines Inc. (TQ&M) systems to the Eastern Townships market. The same transportation systems would be used for the proposed new permit volumes.

2 HEARING

The application was heard by the Board at a public hearing held in Calgary, Alberta, on 7 and 10 August 1984 with V. E. Bohme, P.Eng., G. A. Warne, P.Eng., and H. Antonio, P.Eng., sitting.

Of the seven interventions received by the Board, only Pan-Alberta Gas Ltd., Independent Petroleum Association of Canada, and TransCanada presented evidence. The other interventions were for purposes of cross-examination and argument.

3 INTERVENTIONS

The interveners did not question the volume of reserves under SOQUIP's control, nor the volume of gas which would be surplus to Alberta's requirements. The interveners which presented evidence at the hearing concentrated on matters related to the direct sale of Alberta gas by a producer to a downstream affiliate located outside Alberta. These interveners focused on the implications of direct sales for the Alberta gas industry, which has developed under an implicit set of marketing arrangements which do not make provision for those proposed by the applicant. The interveners questioned whether the proposed removal of gas was in the public interest. Further elaboration on the public interest aspects of the proposed removal appear in section 7. Certain other matters referred to by the interveners and responded to by SOQUIP are described in further detail in section 8, "Other Matters". The Board considers these other matters to be outside its jurisdiction.

4 ISSUES

The Board considers the following to be the issues relevant to its appraisal of the application:

- reserves under contract to SOQUIP,
- gas surplus to Alberta's requirements and permit commitments, and
- public interest aspects of the proposed gas removal.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Societe quebecoise d'initiatives petrolieres	P. Martin
(SOQUIP)	J. L. Roman
D. G. Hart, Q.C.	J. Guerin
	M. Gourdeau
	R. Monjo
	D. Bates
Alberta and Southern Gas Co. Ltd.	
J. R. Smith, Q.C.	
Canadian Hunter Exploration Ltd.	
J. G. Schissel	
Consolidated Natural Gas Limited	
S. F. McAllister	
Independent Petroleum Association of Canada (IPAC)	J. D. Porter
J. P. Peacock	A. P. Markin
C. Seger	
Pan-Alberta Gas Ltd. (Pan-Alberta)	L. H. Larson
K. F. Keeler	
D. A. Dawson	
ProGas Limited	
H. R. Ward	
TransCanada PipeLines Limited (TransCanada)	C. R. Frew
E.W.H. Mallabone	
Energy Resources Conservation Board staff	
C. J. C. Page	
K. Johnston	
M. E. Mumby	
J. L. Boyko	

5 RESERVES UNDER CONTRACT TO SOQUIP

5.1 SOQUIP's Views

SOQUIP's gas reserve estimates for the areas applied for in its application were revised as of 8 August 1984 and totalled some 7.108×10^9 m^3 of established reserves under control.

SOQUIP submitted several deliverability schedules which indicated that it could deliver the applied-for volumes from its supply sources. SOQUIP indicated that it has incorporated additional compression, the recompletion of secondary zones, and new drilling in order to sustain its deliverability requirement in later years of the permit.

Reserves in the Buffalo area are not considered economic at this time but could possibly augment supplies by 1995, depending on general development in that area.

5.2 Board's Views

The Board's estimate of reserves under SOQUIP's control with respect to this application as of 28 August 1984 is some 5.529×10^9 m^3. The Board believes that the established reserves currently under control of SOQUIP are capable of delivering the applied-for volumes over the permit term, and an amount sufficient to make up a deficiency in the reserves available to SOQUIP at the time of its earlier application. The Board also believes that further development in areas such as Buffalo could provide additional supplies before the end of the permit term.

6 GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

All references to reserves in this section are to marketable gas on a 37.4×10^6 joules per m^3 basis.

6.1 Reserves Test

SOQUIP estimated the Alberta reserves surplus as of 31 December 1983 to be 68×10^9 m^3. This estimate was based on total available reserves of 1769×10^9 m^3 (1899×10^9 m^3 of remaining established reserves less deferred and beyond economic reach reserves) and 1701×10^9 m^3 of total requirements (Alberta general requirements, permit-related fuel and shrinkage, remaining permit commitments, and permits pending Order in Council).

TransCanada stated that there was, in all likelihood, sufficient gas surplus to Alberta's needs and sufficient reserves under SOQUIP's control to justify approving SOQUIP's application for an amendment to its existing permit.

The Board has applied its normal reserves test to determine whether the gas volume requested in the SOQUIP application is surplus to Alberta's needs. The Board is satisfied that the 5.108×10^9 m^3 of gas will be surplus to the needs of persons in Alberta and to existing permit commitments.

6.2 Deliverability Test

SOQUIP did not submit a determination of the provincial deliverability surplus.

The Board is satisfied that the applied-for volumes can be delivered while also accommodating Alberta's requirements, existing permit commitments, and permits pending Order in Council.

7 PUBLIC INTEREST ASPECTS OF THE PROPOSED GAS REMOVAL

7.1 Interveners' Views

The interveners stated that various aspects of SOQUIP's proposal could be interpreted as having a significant negative impact on the gas producing industry and thus on the public interest. They argued that the Board had a general responsibility under the Act and Energy Resources Conservation Act to ensure the application was in the public interest.

7.2 SOQUIP's Views

SOQUIP argued that the Act defined public interest so narrowly as to exclude the interveners' concerns and also that since SOQUIP's application was not made under the Energy Resources Conservation Act, it did not apply.

7.3 Board's Views

The Board notes the concerns of the interveners that applications such as SOQUIP's may have the potential to disrupt the current gas marketing system, if significant volumes of gas were to be purchased for direct sale to markets which were not available to all producers. The Board also notes that other direct sales are now taking place. The annual volume applied for by SOQUIP would represent some 10 per cent of gas projected to be sold in the Province of Quebec during 1985. The amount to be sold from reserves owned by SOQUIP, and its major partner ICG, would be slightly more than 4 per cent.

Additionally, the Board believes that public interest as narrowly defined in section 7(3) of the Act excludes the special concerns of the interveners. In the Board's view, granting the SOQUIP application is in the public interest as defined in the Act, which has regard only for the present and future gas requirements of persons in Alberta.

8 OTHER MATTERS

The interveners' evidence and argument, and the responses of the applicant to the interveners' concerns, dealt with matters not typically considered to be Board responsibilities under the Act. The evidence on these matters is summarized here for the information of the government and other interested parties.

8.1 IPAC

In IPAC's view, there were several sources of inequity which would, if the application were approved, benefit SOQUIP at the expense of Alberta producers generally. These were:

- the cost of maintaining reserves surpluses necessary for export permits are borne by producers generally,
- as a result of the above, SOQUIP would share in the export flowback revenue distribution system without sharing in the costs,
- since both capital and operating costs of the TQ&M pipeline are essentially being paid by producers supplying TransCanada and Pan-Alberta, these producers should have access to the markets being served by that pipeline, and
- as the costs of the Marketing Development and Incentive Plan (MDIP) and the Industrial Gas Sales Incentive Plan (IGSIP) are being borne by all producers, there should be equal access to the markets being developed through these programs.

8.2 Pan-Alberta

Pan-Alberta requested the Board deny the application for amendment of SOQUIP's permit for the following reasons:

- Pan-Alberta has previously been authorized by the Board to remove gas from Alberta which was intended for the same market SOQUIP now plans to serve,

- construction of the TQ&M pipeline was predicated on the understanding that TransCanada and Pan-Alberta would have access to the expanding Quebec market,
- NOVA facilities which have been installed to serve Pan-Alberta's Quebec market would be underutilized if Pan-Alberta were to be denied this market,
- approval of the application would result in unnecessary duplication of NOVA facilities to the extent that new facilities would be required to move SOQUIP's gas within Alberta, and
- SOQUIP failed to demonstrate non-discriminatory purchasing practices in acquiring gas within Alberta.

8.3 TransCanada

TransCanada was concerned about several implications of approval of the application and requested the Board give consideration to them. TransCanada's concerns were that:

- the TQ&M pipeline, which was built as the result of the efforts of TransCanada and Pan-Alberta, would be used to move a different company's gas to its own captive market in Quebec at the expense of TransCanada's and Pan-Alberta's producers,
- NOVA facilities which have been built in anticipation of increased TransCanada and Pan-Alberta gas sales in Quebec would be underutilized; these costs would be carried by Alberta producers generally,
- the costs of NOVA facilities required to move the applicant's gas would be borne in part by producers who do not have access to the additional Quebec market to be served by SOQUIP,
- future applications of the type advanced by SOQUIP could seriously erode traditional marketing arrangements in which all producers share in markets, and
- there is no demonstrated benefit to Quebec consumers by purchasing gas from SOQUIP as opposed to TransCanada or Pan-Alberta.

8.4 SOQUIP

In rebuttal evidence and final argument, SOQUIP suggested to the Board that the matters raised by the interveners are beyond the Board's jurisdiction.

SOQUIP's responses to the issues raised by the interveners are summarized below:

- With respect to IPAC's concerns about equal sharing of markets and equal sharing of the costs of various incentive plans, SOQUIP stated that there has always been differential sharing by all producers of the markets and of the marketing costs, and therefore that it was prejudicial to single out SOQUIP for special criticism.
- In response to Pan-Alberta's and TransCanada's claim that they should be the sole suppliers to the Quebec gas market, SOQUIP stated that to all intents and purposes Pan-Alberta and TransCanada will continue in this role even if the application is granted, since SOQUIP's own gas would supply only 2 per cent of the market.
- Regarding the utilization of NOVA facilities, SOQUIP submitted that the utilization of existing facilities would be increased and that the cost of additional facilities would be minor relative to the total investment if the application were granted.
- In response to Pan-Alberta's allegation that it failed to demonstrate non-discriminatory purchasing practices, SOQUIP stated that it has 26 producers under contract.

9 OTHER CONDITIONS OF THE PERMIT

9.1 Permit Term

SOQUIP has applied to extend its permit term for a period of 2 years from 1 November 1997 to 31 October 1999, a term which corresponds to SOQUIP's proposed sales agreement with GICQ. The Board believes the applied-for term is appropriate.

9.2 Maximum Daily and Annual Volumes

SOQUIP applied to increase its annual permit volume by 340.545×10^6 m^3 to 408.075×10^6 m^3 for the full permit term and to increase its maximum daily volume by 933×10^3 m^3 to 1.118×10^6 m^3 during the period 1 November 1984 to 31 October 1997, and thereafter for a maximum daily volume of 933×10^3 m^3 to 31 October 1999. These are the volumes specified in SOQUIP's proposed sales agreement with GICQ. The Board believes the applied-for annual and daily permit maximums are appropriate.

9.3 Pools, Fields, and Areas

Gas Removal Permit SQ 83-1 names 11 pools, fields, and areas from which SOQUIP may obtain gas for removal from the province. SOQUIP applied to name an additional 15 pools, fields, and areas in the permit. In assessing the reserves available to SOQUIP, the Board has designated new fields and revised existing field boundaries. Accordingly, the Board is prepared to add 18 pools, fields, and areas to the permit. These pools, fields, and areas, as shown in the form of permit amendment in the appendix, are those in which the Board recognizes reserves available to SOQUIP.

9.4 Special Permit Clause

SOQUIP has requested an "augmenting" clause in its permit amendment which would allow removals in excess of the specified annual maximum to the extent that removals in the preceding 4-year period were less than the annual maximum. This clause appears in several permits and the Board believes that it would be reasonable to afford SOQUIP this degree of flexibility. However, as applied for by SOQUIP, and as written in existing permits, such augmentations are limited by the daily maximum. Since SOQUIP's proposed annual maximum is simply the daily maximum multiplied by 365 days per year, augmentation of the annual volume without exceeding the daily maximum is not possible. The Board is not prepared to modify the augmenting clause such that the daily maximum would be exceeded and, consequently, the Board would not include the clause in the proposed SOQUIP permit amendment.

10 FINDINGS AND DECISION

In light of its findings and responsibilities under the Act, the Board, with the approval of the Lieutenant Governor in Council, is prepared to amend SOQUIP's Gas Removal Permit SQ 83-1. The proposed amendment would be in the form shown in the appendix and would be subject to the terms and conditions therein contained as well as any conditions imposed by the Lieutenant Governor in Council.

DATED at Calgary, Alberta, on 10 October 1984.

ENERGY RESOURCES CONSERVATION BOARD

VE Bohme

V. E. Bohme, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

Antonio

H. Antonio, P.Eng.
Acting Board Member

APPENDIX FORM OF PERMIT AMENDMENT *

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of a permit to Societe quebecoise d'initiatives petrolieres authorizing the removal of gas from the Province

AMENDMENT OF PERMIT NO. SQ 83-1

WHEREAS Societe quebecoise d'initiatives petrolieres is the holder of Permit No. SQ 83-1 authorizing the removal of gas from the Province; and

WHEREAS Societe quebecoise d'initiatives petrolieres has applied to the Energy Resources Conservation Board to amend Permit No. SQ 83-1; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council numbered O.C. ____________________ and dated ________________________ .

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3 of the Revised Statutes of Alberta, 1980, hereby orders as follows:

1. Permit No. SQ 83-1 is amended.

2. Clause 1 is amended by striking out "31 October 1997" and by substituting "31 October 1999".

3. Clause 2, subclause (a) is amended by striking out "1 000 000 000" and by substituting "6 108 000 000".

4. Clause 2, subclause (b) is amended by striking out "185 000 cubic metres" and by substituting "1 118 000 cubic metres during the period 1 November 1984 to 31 October 1997 and 933 000 cubic metres during the period 1 November 1997 to 31 October 1999"; and by striking out "67 530 000" and by substituting "408 075 000".

5. Clause 4, subclause (1) is amended by adding the following pools, fields and areas to the list from which gas may be obtained for removal from the Province:

Chard Field
Clive Field
Donalda Field
Earring Field
Girouxville East Field
Kaybob Field
Liege Field
Manito Field
Minnehik-Buck Lake Field
Newby Field
Philomena Field
Progress Field
Provost Field
Redwater Field
Tweedie Field
Westerose South Field
Willesden Green Field
Wolverine Field

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

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* This is only a form of permit amendment. The permit amendment, when issued, may have minor variations from that set out here.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY FEDERATED PIPE LINES LTD. AND PEACE PIPE LINE LTD. FOR APPROVAL TO AMEND PIPELINE LICENCES AND FOR PERMITS TO CONSTRUCT PIPELINES TO TRANSPORT HIGH VAPOUR PRESSURE PRODUCTS IN THE FORT SASKATCHEWAN, MORINVILLE, AND SWAN HILLS AREAS

Decision D 84-22
Applications 830394 and 840496

1 INTRODUCTION

1.1 The Applications

Application 830394

Federated Pipe Lines Ltd. (Federated) applied to the Energy Resources Conservation Board (the Board) under sections 7, 13, and 23 of the Pipeline Act for the following conversions and construction as shown on the attached map:

(a) the conversion of a 14-kilometre (km) section of the existing 273.1-millimetre (mm) pipeline from Namao to Morinville to high vapour pressure (HVP) service;

(b) the conversion of a 166-km section of the more recently constructed 406.4-mm pipeline from Morinville to Sarah Lake to HVP service;

(c) the conversion of an 11-km section of Federated's existing 273.1-mm pipeline from Sarah Lake to Swan Hills to HVP service;

(d) the construction of the proposed 273.1-mm pipeline from Fort Saskatchewan to Namao;

(e) the construction of approximately 9 km of 273.1-mm pipeline within a new right of way around the Town of Morinville;

(f) the construction of 1.4 km of 168.3-mm pipeline from Whitecourt Junction to tie into the Esso fieldgate in legal subdivision 11, section 6, township 64, range 10, west of the 5th meridian (11-6-64-10 W5M);

(g) the construction of a portion of the 219.1-mm pipeline extension northwest of Swan Hills to tie into the Home Oil 2-6 solvent injection plant location; and

(h) the construction of a booster station on the 406.4-mm line near the junction of the 406- and 273.1-mm pipelines at 4-15-63-7 W5M.

Application 840496

Peace Pipe Line Ltd. (Peace Pipe) applied to the Board pursuant to Part 4 of the Pipeline Act to construct a meter station in 11-14-55-22 W4M and approximately 23.49 km of 323.9- and 273.1-mm outside diameter (OD) pipeline to transport HVP products from a pipeline in 4-35-54-24 W4M to a cavern storage facility in 3-14-55-22 W4M.

1.2 The Hearing

Federated's and Peace Pipe's applications were considered at a public hearing on 14 August 1984, at Edmonton, Alberta, with V. E. Bohme, P.Eng., G. A. Warne, P.Eng., and H. Antonio, P.Eng., sitting. Participants at the hearing are identified in the attached table.

1.3 Background

In October 1983, the Board heard applications by Federated for amendment of existing pipeline licences and for a permit to construct new pipelines for the transport of HVP products from the Edmonton area to the Swan Hills and Judy Creek areas for miscible-flood schemes. The licence amendments provided for conversion of existing lines from crude oil to natural gas liquids (NGL) service.

In Decision D 83-28, the Board indicated that it was prepared to amend the existing licences subject to the successful completion of a prescribed inspection and testing program for the pipelines to be converted to HVP service. It was also prepared to issue a permit for the construction of the proposed pipelines for the Fort Saskatchewan to Namao section and the sections in the Swan Hills and Judy Creek areas. However, the Board indicated that it was not prepared to approve the new line through Morinville, but required that Federated consider a route around Morinville that would maintain a reasonable separation distance between the town boundary and the pipeline.

Subsequently, Federated submitted an amended application with three significant changes, namely:

(1) rerouting the proposed pipeline from Namao to Fort Saskatchewan,

(2) rerouting part of an existing line around the Town of Morinville, and

(3) conversion of 406.4-mm pipe to HVP service rather than existing 273.1-mm pipe for most of the previously applied-for HVP line.

APPLICATION 830394 (Federated)

2 THE ISSUES

The Board believes the issues pertinent to Federated's application are the suitability of the proposed:

- rerouting of the pipeline from Namao to Fort Saskatchewan,
- substitution of 406.4-mm pipe for the previously approved 273.1-mm pipe, and its suitability for HVP service,
- rerouting around the Town of Morinville, and
- pipeline routing through Mr. Chepil's land.

2.1 Views of Federated

Federated indicated that the purpose and necessity of this pipeline is the same as that of the line described in the original application. The purpose of the project is to provide for the transport of natural gas liquids from the Edmonton area to the Swan Hills and Judy Creek areas for use in proposed miscible-flood schemes for enhanced oil recovery. Federated stated that only part of the volumes of NGLs needed for the proposed miscible-flood schemes are available in the Swan Hills and Judy Creek areas and that the additional volumes required have to be transported from the Deep Basin or the Fort Saskatchewan areas.

As Peace Pipe intended to build a pipeline from Namao to the storage caverns in Fort Saskatchewan, it was decided that laying both Federated's and Peace Pipe's pipelines in a common ditch would lower construction costs and minimize surface interference. Federated stated that the pipeline from Fort Saskatchewan to Namao was rerouted to provide a more direct route. The new route includes a crossing of the North Saskatchewan River but avoids the originally proposed crossing of the Sturgeon River.

In response to the Board's direction, contained in Decision D 83-28, that any pipeline be rerouted around the Town of Morinville by at least 1000 feet (305 metres (m)), Federated has proposed to by-pass the eastern town limits by three-quarters of a mile (1210 m) and the northern town limits by half a mile (800 m). In addition, Federated stated that it would construct this pipeline to zone 2 standards, as defined in CSA Z183-M1982.

Federated was obligated by the Board's requirement in Decision D 83-28 to reduce the maximum operating pressure of the 273.1-mm line. It stated that this restricted the throughput of the pipeline such that there was not sufficient surplus capacity to accommodate additional future projects. It also indicated that the required capacity of the line had increased from the initially estimated 43 600 barrels per day (bpd) (6930 cubic metres per day (m^3/d)) to 60 000 bpd (9540 m^3/d) due to expected additional miscible-flood projects in the Swan Hills area. As Federated has the flexibility to convert either the 273.1-mm or the 406.4-mm pipeline to natural gas liquids transport, it now prefers the larger pipeline. Federated stated that it would have the capacity to transport 60 000 bpd of HVP liquid through the 273.1-mm and 406.4-mm combined system proposed in the revised application. Also, the alignment of the 406.4-mm line would enable Federated to serve the Esso ethane extraction plant at 15-25-64-11 W5M.

Federated stated that the 406.4-mm line was 11 years newer than the 273.1-mm line and so there was a significant difference between the two lines in the steel and the pipe manufacturing technology. The 406.4-mm pipe is made of semi-killed steel which is generally more uniform and of better quality than the rimmed steel used for the 273.1-mm pipe. Low-frequency welding had been replaced by the high-frequency welding process in the newer pipe resulting in a reduction of the number of failures of the long seam weld.

Initially, Federated (and Peace Pipe) intended to construct the pipeline in a diagonal alignment across Mr. Chepil's property. However, upon consideration of Mr. Chepil's concerns regarding land disturbance, Federated (and Peace Pipe) agreed to follow the quarter-section lines on Mr. Chepil's land.

2.2 Views of the Interveners

Mr. Chepil, owner of the northeast quarter of 6-55-23 W4M, expressed concern regarding the diagonal route originally proposed across his property but was satisfied with Federated's and Peace Pipe's final proposed routing of the pipeline along the quarter-section lines of his property.

2.3 Views of the Board

The Board agrees with Federated that construction costs and environmental damage would be reduced by placing both the Federated pipeline and the Peace Pipe pipelines in one ditch. It acknowledges Federated's statement that the more direct route and the single river crossing for both lines make the proposed route from Fort Saskatchewan to Namao less costly.

The Board agrees with the rerouting of the pipeline around Morinville and considers the design of pipeline in this area to zone 2 requirements, to accommodate future development, to be prudent.

The Board accepts Federated's evidence regarding the suitability of the 406.4-mm line for conversion to HVP service. However, the Board would require that all segments of the pipeline be hydrostatically pressure tested and at each break or leak location, the full length of pipe (joint) containing the failure be replaced. On each failed section of pipe, the company would be required to perform the following tests and inspections:

(a) two tensile tests (each joint) — mill weld
(b) two guided bend tests (each joint) — mill weld
(c) two nick fractures (each joint) — mill weld
(d) one 12 o'clock flattening test (each joint)
(e) one 3 o'clock flattening test (each joint)
(f) one microspecimen — mill weld
(g) one chemical analysis (each joint)

All test results shall be submitted to the Board.

The Board notes that Mr. Chepil's concerns regarding pipeline routing through his property have been resolved.

APPLICATION 840496 (Peace Pipe)

3 THE ISSUES

The Board believes the issues pertinent to Peace Pipe's application are:

- necessity of Namao to Fort Saskatchewan pipeline, and
- the suitablility of the route selection.

3.1 Views of Peace Pipe

Peace Pipe stated that an interconnection between its present Deep Basin line to Edmonton and Federated's HVP line in the vicinity of Namao can-not be made because the volumes of natural gas liquids transported by Peace Pipe fluctuate seasonally and are batched at high flow rates while the miscible flood projects in the Swan Hills area would require a uniform, uninterrupted flow of liquids. Peace Pipe noted that the cavern storage available at Fort Saskatchewan can be used to smooth out the fluctuations and so provide flexibility to the miscible flood operations. Also, Fort Saskatchewan is a major assembly point for natural gas liquids in the province. Therefore, as both supply and demand from the Peace Pipe and Federated systems have to be accommodated, the possible connection at Namao would not be practical.

Peace Pipe also expects an increase in the usage of ethane mix by the petrochemical industry in Fort Saskatchewan. The Namao to Fort Saskatchewan leg would be necessary to transport the NGLs directly to Fort Saskatchewan.

According to Peace Pipe, the construction of the pipeline across the river would not pose any unusual engineering problems. The two pipe strings would be assembled on the west side of the river, concrete-coated and banded together, and winched over to the other side of the river. The minimum depth of cover across the river is designed to be 3 m.

3.2 Views of the Board

The Board is satisfied with the necessity of the Namao to Fort Saskatchewan leg. It considers the route suitable and believes that the crossing of the Fort Saskatchewan River would present no unusual engineering problems.

4 DECISION

The Board is prepared to issue permits for the new construction proposed in Applications 830394 and 840496, subject to the rerouting agreed to along the boundaries of Mr. Chepil's land, and receipt of appropriate ministerial approvals.

The Board is also prepared to approve amendments to licences (Licences 114, 7574, 7659, 8026, and 904) as proposed in Application 830394 for the conversion of existing pipelines (licences) from crude oil to high vapour pressure products service. These approvals will be subject to the successful completion of the testing program specified in Section 2 of this report.

DATED at Calgary, Alberta on 18 September 1984.

ENERGY RESOURCES CONSERVATION BOARD

V E Bohme

V. E. Bohme, P.Eng.
Board Member

G. A. Warne

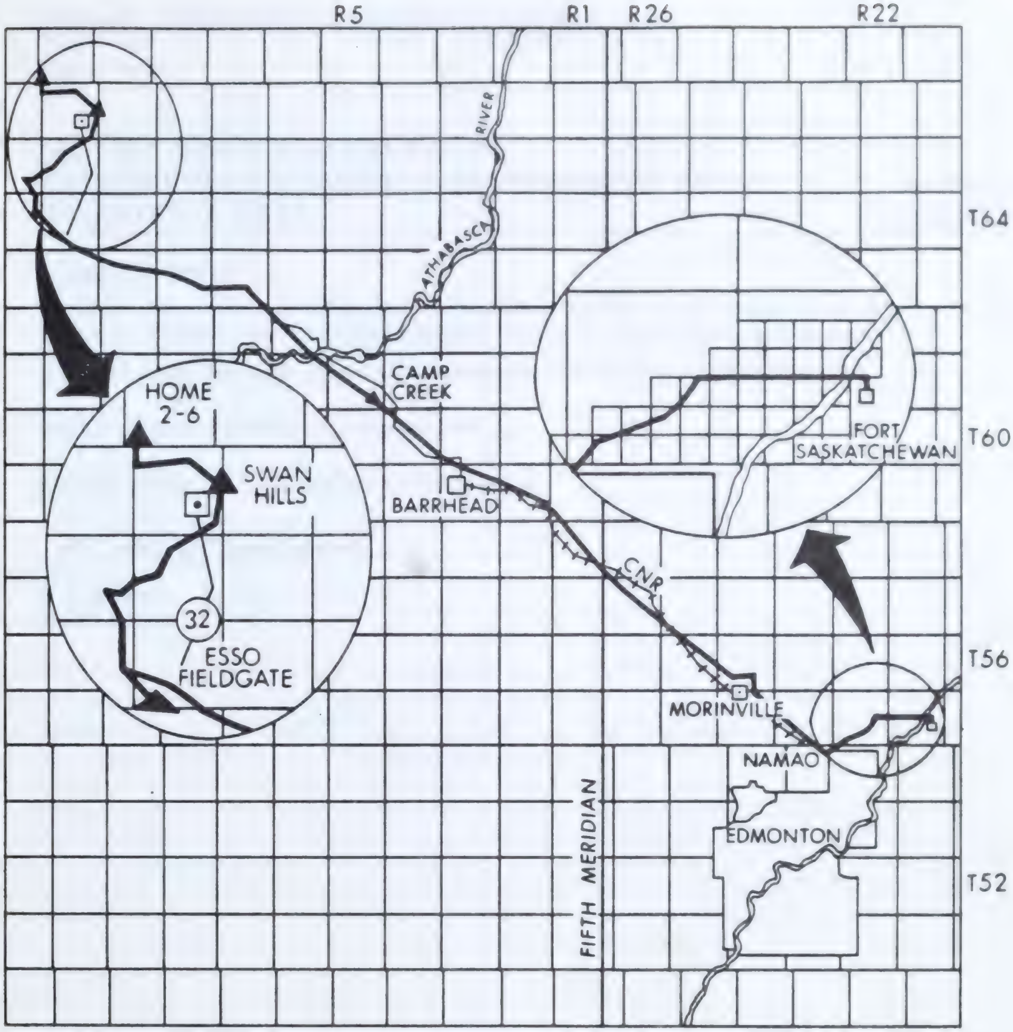
G. A. Warne, P.Eng.
Acting Board Member

Antonio

H. Antonio, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Federated Pipe Lines Ltd. (Federated) R. M. Perrin C. A. Keck	R. C. Osborne J. L. McClennan G. R. Evans A. M. McLean, P.Eng. (of A. Murray McLean & Associates Ltd.) M. Massecar, P.Eng. S. J. Stefanowski J. R. Wurzer
Peace Pipe Lines Ltd. (Peace Pipe) C. K. Yates	J. A. Ion R. D. Avery B. Harris
N. Chepil (Mr. Chepil) N. Chepil	N. Chepil
Alberta Environment T. Bossenberry	
Energy Resources Conservation Board staff R. Hansford A. Cassley, P.Eng. N. C. Harris, P.Eng.	



FEDERATED PIPE LINES LTD.
PEACE PIPE LINE LTD.
APPLICATIONS NO. 830394 AND 840496
FORT SASKATCHEWAN - SWAN HILLS AREA

D84-22
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BIEWAG ENERGY RESOURCES LTD.
AMENDMENT OF INDUSTRIAL DEVELOPMENT PERMIT
WASKATENAU AREA

Decision D 84-23
Application 840031

BOARD DECISION

The Board concurs with the findings and recommendations of Mr. V. Millard and Mr. N. Strom with respect to Application 840031 by Biewag Energy Resources Ltd. for the reasons set out in their report.

The Board directs that Application 840031 be approved with the recommended conditions.

DATED at Calgary, Alberta, on 3 October 1984.

ENERGY RESOURCES CONSERVATION BOARD

VE Bohme

V. E. Bohme
Board Member

1 INTRODUCTION

1.1 Application

Biewag Energy Resources Ltd. (Biewag) applied, pursuant to section 30 of the Oil and Gas Conservation Act, for amendments to clause 10 of Industrial Development Permit BER 82-5, and to paragraph 1 of Attachment 1 to Order in Council (O.C.) 1129/82 as amended. At the hearing, Biewag applied for a further amendment, to paragraph 2 of Attachment 1 to O.C. 1129/82. Biewag requested that the dates stipulated in clause 10 of the permit and paragraphs 1 and 2 of Attachment 1 to the O.C., all be amended to read 30 June 1985.

Biewag also stated in its application that a change had occurred in its original proposal, inasmuch as one sales customer had been anticipated and three or four customers appear now to comprise the market for the methanol to be produced.

1.2 Hearing

A public hearing of the application was held in Calgary, Alberta, on 17 July 1984 with V. Millard and N. Strom, P.Eng., sitting.

Those who appeared at the hearing are shown in the following table.

1.3 Background

In 1982 Biewag obtained an industrial development permit to use 1800 million cubic metres of natural gas annually in the production of fuel grade methanol, over a 15-year term. Clause 10 of the permit stipulated 30 June 1983 as the date by which Biewag was to satisfy the Board that construction of its methanol project had commenced. Paragraph 1 of Attachment 1 to O.C. 1129/82, which authorized the Board to grant the permit, stipulated 1 March 1983 as the date by which Biewag was to satisfy the Minister of Economic Development as to the Alberta content of the project, and paragraph 2 stipulated 30 March 1983 as the date by which Biewag was to satisfy the Minister of Energy and Natural Resources respecting the price to be paid for gas used in the project.

A further condition of the permit required Biewag to provide, in confidence, an executed copy of its sales contract to the Minister of Economic Development prior to commencement of construction.

On 13 April 1983, O.C. 343/83 authorized the amendment of Biewag's permit to allow the Board discretionary power to stipulate a later date in clause 10 (commencement of construction), upon application

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Biewag Energy Resources Ltd. (Biewag)	R. Gordon Cormie
J. R. Smith, Q.C.	
Celanese Canada Inc. (Celanese)	J. K. Lambie
J. J. Marshall	
Alberta Gas Chemicals Ltd. (AGCL)	K. McCrae
B. G. Nemetz	
PanCanadian Petroleum Limited (PanCanadian)	
W. J. Hope-Ross	
Trans Mountain Pipe Line Company Ltd. (Trans Mountain)	
M. W. P. Boyle	
County of Lamont No. 30	
A. W. Cholak	
Town of Lamont	
S. Andrais	
Village of Waskatenau	
V. Ceklic	
W. T. Jarrell	
Energy Resources Conservation Board staff	
C.J.C. Page	
K. Johnston	
M. E. Mumby	
J. L. Boyko	

therefor by the Permittee. Attachment 1 to O.C. 343/83 was also amended to stipulate 1 July 1983 in paragraph 1, and 30 March 1985 in paragraph 2. On 29 June 1983, at the request of Biewag, the Board stipulated 30 October 1983 as the date prior to which Biewag was to satisfy it that construction of the methanol project had commenced.

On 20 October 1983, Biewag requested a further stipulation respecting clause 10 of the permit, to amend the date therein to 31 December 1983. In the same letter, Biewag requested an amendment to the date in paragraph 1 of Attachment 1 to O.C. 1129/82 (Alberta content), to make it read 31 December 1983 as well. The Board subsequently called a hearing for the purpose of hearing representations respecting a further application by Biewag for amendment of the stipulated dates to 30 June 1985.

2 PARTICIPANTS' VIEWS

2.1 Biewag

Biewag stated that although its original proposal anticipated only one customer for the output of its proposed plant, it appears now that there will be three or four. Referring to the condition of its permit concerning confidential advice to the Minister of Economic Development respecting the sales contract to a single European purchaser, Biewag stated that it was not applying for a variation of the condition because it believed that the application still conforms with the intent of the condition. Stating further that although the economic picture for methanol has deteriorated since 1982, the stable political and economic climate of Alberta will, in Biewag's opinion, result in some premium value to supplies coming from Alberta. Biewag also stated that construction costs are materially lower than in 1982, and that it believes the application can still proceed on the basis of current price forecasts. The applicant maintained that it is applying for nothing more than the extensions of certain time periods so that it can proceed with its project.

2.2 Celanese

Celanese stated that it did not oppose the extension of dates in the Biewag permit provided that the conditions of the permit, particularly those regarding marketing of the methanol produced, were retained without modification. Celanese expressed concern that it would be difficult to monitor compliance with the marketing conditions of the permit if a large number of European customers were involved. Celanese also stated that the Biewag project has less economic viability now than it did at the time of the original application, at which time Celanese had concluded that the project lacked economic viability.

2.3 AGCL

AGCL stated that the nature of Biewag's application has changed significantly in that it is now proposing to service a normal growing market rather than a particular project. AGCL stated that a move from one purchaser to three or four does not stand up to the analysis and philosophy of the Board's initial ruling, and that an incremental growth in the fuel methanol market of the world should be available to normal producers. AGCL also stated that there is no real difference between fuel methanol and chemical methanol with respect to price and end uses, and that AGCL is itself supplying the fuel methanol market in Europe at the present time. AGCL submitted that it would have no problem with the time extensions requested by Biewag, but to the extent that Biewag is asking for a change in the initial requirement of the Board that there be one contract in place, a new hearing should be called.

2.4 PanCanadian

PanCanadian adopted the argument of Celanese, with respect to the assessment of both marketing and economics as applied to the Biewag project. PanCanadian further stated that unless the Board is satisfied that there is a market for the extra methanol, a viable plant may require reduced gas prices within the province.

2.5 Trans Mountain

Trans Mountain filed a submission in support of the application, confirming that it has had discussions with the applicant concerning the transportation of methanol through its pipeline system. Trans Mountain also stated that it would be prepared to construct and operate a feeder line to transport methanol from the proposed plant to its terminal facilities in Edmonton, and that it considers its pipeline to be a practical means of transporting the plant's output to tidewater on the west coast.

2.6 Others

The County of Lamont No. 30, the Town of Lamont, and the Village of Waskatenau all filed submissions in support of the application, stating in their submissions that the Biewag project would have favourable economic impacts on their communities. Mr. W. T. Jarrell filed a submission for the purpose of asking general questions at the hearing.

3 BOARD VIEWS

None of the interveners opposed amendment of the date in clause 10 of the permit nor of the dates in paragraphs 1 and 2 of Attachment 1 to O.C. 1129/82. The Board is satisfied that it would be in the public interest to grant the application and amend the dates specified in the permit and order in council.

4 RECOMMENDATION

The presiding members recommend that:

- the date in clause 10 of Industrial Development Permit BER 82-5 be amended to read 30 June 1985 instead of 30 October 1983, and
- the application be referred to the Lieutenant Governor in Council in respect of paragraphs 1 and 2 of Attachment 1 to O.C. 1129/82.

DATED at Calgary, Alberta, on 3 October 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

NEW FACILITIES AT THE SYNCRUDE MILDRED LAKE OIL SANDS PLANT

Decision D 84-24
Application 840142

1 INTRODUCTION

1.1 Application and Hearing

Syncrude Canada Ltd. (Syncrude) applied pursuant to section 14 of the Oil Sands Conservation Act to amend Syncrude's existing Approval 2959 to:

- Increase the yearly synthetic crude oil production from 7 507 000 cubic metres (m^3) to 8 000 000 m^3 and produce 370 000 m^3 of naphtha product.
- Extend the approved life of the project to 31 December 2013.
- Modify existing equipment and construct new facilities including:
  - — A bitumen hydrocracker,
  - — A mid-distillate hydrotreater,
  - — An additional sulphur recovery unit,
  - — A sulphur plant tail-gas clean-up facility,
  - — A light ends recovery facility,
  - — An additional hydrogen unit, and
  - — Enhanced gravity settlers.

The application was heard by the Board on the 20th and 21st of August 1984. On the 20th of August, Syncrude submitted a "Biophysical Impact Assessment for the New Facilities at the Syncrude Canada Ltd. Mildred Lake Plant". At the request of the interveners, the hearing was adjourned to permit a review of the document. The hearing reconvened on the 24th of September and concluded on the 25th of September 1984, with V. Millard, V. E. Bohme, P.Eng., and N. Strom, P.Eng., sitting.

The participants in the hearing are listed in the table.

1.2 Background to the Application

In 1968, Syncrude was granted approval to produce synthetic crude oil from Bituminous Sands Lease 17 in the Athabasca Wabiskaw-McMurray Oil Sands Deposit. Presently, Syncrude has approval to produce 7 507 000 m^3 of synthetic crude oil annually and the current approval expires on 31 December 2004.

The Syncrude project, which commenced production in 1977, comprises an open-pit mine using draglines, bucket-wheel reclaimers, and conveyors to transport the bituminous sands to an extraction plant where a hotwater process is used to separate bitumen from the sand. Wastes from the extraction plant are clean sand, wet tailings sludge, and tailings water, all of which are currently directed to the tailings pond. In future, mined out areas will be used for tailings sand storage. The bitumen is upgraded to synthetic crude oil using fluid coking and hydrotreating processes. Solid by-products include sulphur, which is marketed, and coke, which is stored.

In July 1983, Syncrude and Alberta's Minister of Energy and Natural Resources announced agreement on special fiscal terms related to additional capital investments for the Capacity Addition Program over a 5-year period.

2 ISSUES

The Board considers the main issues to be:

- The proposed expansion.
- Extension of the term of project approval by a further 9 years to 31 December 2013.
- Sulphur dioxide (SO_2) and particulate emission limits.
- Other environmental, social, and economic issues.

3 THE PROPOSED EXPANSION

3.1 Applicant's Views

Syncrude stated that the proposed modifications and additions would result in an increased yield of synthetic crude oil, while reducing the amounts of coke and fuel gas that are produced using the current technology. The modifications would also improve the environmental performance of the Syncrude plant. The new process units would provide greater operating flexibility and improved continuity of daily operations. The combination of the bitumen hydrocracker, the new sulphur plant, and the Sulfreen tail-gas recovery unit are designed to reduce SO_2 emissions by 18 per cent of the current design level.[1]

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[1] Current design level after debottlenecking is 282 tonnes per day (t/d) SO_2. The design level after the proposed expansion is 229 t/d SO_2.

Syncrude stated that the following benefits would result from the proposed expansion:

- Stimulate the Albertan and Canadian economies.
- Promote oil self-sufficiency by increased synthetic crude oil and naphtha production of 4750 m^3 per day.
- Generate 26 000 man-years of direct and indirect employment, 24 000 of them in Alberta.
- Create 375 new jobs by 1987.
- Add 1200 people to the population of Fort McMurray.
- Increase consumer spending in Fort McMurray by more than $8 million yearly.
- Increase Alberta government royalties by $5.6 billion over the life of the plant and increase federal and municipal tax revenues.
- Increase Native involvement due to new job rotation programs and a plan to increase Native opportunities through jobs and retraining.
- Utilize and demonstrate new technology.

3.2 Interveners' Views

The Fort McKay Indian Band (Band) indicated that it is ill equipped to determine the effects of the industry on its community other than through observations that include unexplainable community illnesses, bitter tasting water and snow, and the gradual disappearance of wildlife and berries. The Band also referred to the general social and economic impacts from oil sands operations in the area. It acknowledged that if SO_2 emissions were decreased through the Syncrude expansion some of their concerns would be partially alleviated, although adequate environmental monitoring and studies need to be done to assess the current and possible future impact on their environment.

The Band contended that the applicant should install the best available technology to reduce emissions and specifically recommended that the Board consider requiring the installation of Flue Gas Desulphurization (FGD).

Alberta Trapper's Association (Mr. Rogers) also expressed concern about environmental and social impacts, and recommended that particulate emissions from the plant should be reduced.

The McMurray Manufacturers Association and the Fort McMurray Chamber of Commerce stated their support for the proposed expansion. The Fort McMurray Chamber of Commerce believes that the economic benefits of the project are required and that environmental impacts are adequately controlled by existing legislation.

3.3 Board's Views

The Board is satisfied that the expansion program is generally appropriate in that it will provide benefits in resource conservation and environmental impact mitigation, as well as generating economic benefits. It will result in increased synthetic crude oil and sulphur production, reduced SO_2 emissions, and implementation of new technology which is particularly important to technological advancement in the oil sands industry. The proposal will also result in both immediate and long-term economic benefits including increased employment to the local community, Alberta, and Canada. The specific recommendations of the Band and Mr. Rogers to further reduce emissions are considered in section 5.

4 EXTENSION OF THE TERM OF PROJECT APPROVAL TO 31 DECEMBER 2013

4.1 Applicant's Views

The proposed new facilities are expected to have a useful life of 25 years. Syncrude stated that the project life must be extended a further 9 years to ensure sufficient return on investment from the new facilities. Syncrude noted that there are adequate bitumen reserves within the currently approved project area to sustain the expanded project to year 2013. Syncrude indicated that it plans to file an application in the next 1 to 4 years to expand the required mining area. It acknowledged that new mine area over and above that currently approved would be required for the expanded plant, but was willing to assume the risk that such could be obtained.

4.2 Interveners' Views

The Band stated that granting an extension to 2013 should not proceed without a public hearing at which all aspects of Syncrude's operation could be examined. It contended that without some indication of the possible cumulative effects of emissions, the extension may not be in the community's best interest. Further studies, research programs, and community monitoring are needed in this respect before such a request should be approved.

4.3 Board's Views

The Board recognizes the need to extend the project life for reasons of project economics of the expansion. With regard to cumulative environmental impacts, the operation is currently and will in the future be required to meet Alberta environmental standards which are designed to protect health and the environment. The Board is not aware of any scientific field studies that demonstrate significant environmental impacts from the operation of the Syncrude plant. The Board recognizes that the Band and Mr. Rogers do not agree with some of the assessments made to date and those matters are addressed in section 6. The Board agrees that more effort should be put into long-term environmental impact studies.

5 SO_2 AND PARTICULATE EMISSION LIMITS

5.1 Applicant's Views

With the addition of the new sulphur plant and the Sulfreen tail-gas clean-up facility, the SO_2 emissions from Syncrude would be reduced on a design basis by 18 per cent. The new sulphur plant would not only provide Syncrude with the needed additional capacity, but would increase reliability in times of upset by providing spare capacity equivalent to one of the existing sulphur plants. These additions would significantly reduce Syncrude's acid gas flaring and improve Syncrude's environmental performance in regard to long-term cumulative emissions.

Syncrude applied for a 90-day rolling average SO_2 emission rate of 265 t/d in place of the current limit of 292 t/d, in addition to continuation of the current hourly limit of 16.4 tonnes. It contended that the 90-day averaging system would be a sufficient means of ensuring environmental protection and that the 265 t/d limit was required because of day-to-day variation in bitumen feed, operational problems, and differences between design and performance. Syncrude testified that average annual emissions would be significantly less than the 265 t/d proposed limit.

Syncrude stated that the particulate emissions from the electrostatic precipitators (ESPs) would increase only marginally and would have no impact on the environment. A study commissioned by Syncrude found that estimated ambient levels of particulate matter and metals were more than 100 times lower than any published air quality standards or guidelines.

With respect to the recommendations by the Band, Syncrude stated that FGD is not technically feasible for its operation. Additionally, it asserted that if FGD were to be required, it would not proceed with the project. With respect to Mr. Rogers' proposal, Syncrude stated that it was not technically feasible to install a crossover linkage between the CO boilers.

5.2 Interveners' Views

The Band stated that a reduction in the SO_2 emissions by Syncrude would be a positive step. But it went on to state that means of reducing the emissions from the coker burner off-gas, the major contributor to SO_2 emissions, should have been addressed. The Band referred to FGD technology and requested the Board to require Syncrude to install such pollution control technology as part of the applied-for expansion.

The Band questioned both the rolling average concept and the proposed limit. It argued that an emission rate of 265 t/d provides more than an adequate buffer and that the rolling average is not necessary.

Alberta Environment questioned the administrative feasibility of the 90-day rolling average. In response, Syncrude suggested continuing with the current system as well as the rolling average system for a test period.

Mr. Rogers proposed that, to reduce particulate emissions, Syncrude should investigate the possibility of a crossover linkage between the CO boilers that would enable Syncrude to reduce the effects of CO boiler shut-downs and reduce the use of the divertor stacks.

5.3 Board's Views

With respect to the Band's recommendation that SO_2 emissions be reduced further than proposed by Syncrude through requiring the installation of FGD equipment, the Board notes that no evidence or expert testimony was presented by the Band to support either technical or economic practicability of FGD for the Syncrude operation. The Board believes that the complexity of the Syncrude operation would bear heavily on the technical practicability of FGD operation and would require very detailed engineering investigation. At the same time, the extensive environmental monitoring and research programs that have been conducted to date have not indicated any significant environmental impacts and the expansion program will allow future emissions to be reduced. Having regard for all of these matters, the Board does not believe it would be appropriate to require the installation of FGD equipment in connection with this application.

With respect to Mr. Rogers' proposal that particulate emissions be reduced by installing a crossover linkage between the CO boilers, the Board notes that Syncrude provided evidence that such a system would not be possible without the addition of another CO boiler. Additionally, the evidence respecting deposition of metals and particulate emissions does not indicate any need for special controls. The Board, therefore, will not require that modification.

The Board has reviewed the extensive discussion respecting the SO_2 limitations that should be specified in the permit. As the Board sees it, this is primarily an administrative question, but it recognizes the importance of arriving at an arrangement that will be appropriate for the operator, the regulators, and the people in the area. It believes it will require some time to assess each of the alternatives and therefore defers finalizing the specification of the emission limits. Upon completion of the assessment, the Board will issue an addendum report and then seek the approval of the Lieutenant Governor in Council for a new permit.

6 OTHER ENVIRONMENTAL, SOCIAL, AND ECONOMIC ISSUES

The Band and Mr. Rogers raised a number of issues that related to alleged impacts from oil sands operations. Some of the more important issues were:

- Social and economic concerns.
- Health concerns.
- Contaminated snow and rain water.
- Supplies of fish and game.
- Impact on trees and berries.
- Potable water supply.
- Oil sands plant emissions.

It appears to the Board that several of these matters are beyond its jurisdiction and not related to the application. Additionally, they are likely the inevitable result of major industrial developments in the area and the significant change in population density. Nevertheless, the Board is concerned about the wide differences in views between some of the local residents and the operators respecting environmental impacts. The studies and various assessments do not, in the Board's view, appear to address the concerns of the local people. For example, it appears to the Board, that some of the concerns of the local people, such as contaminated snow and rain water, have not been evaluated.

An apparent major deficiency relates to the lack of communication between those conducting impact studies in the area and the concerned local citizens. If the latter are not aware of a study, do not have input into it, and are not aware of or do not understand its results, it is not surprising they are not influenced by it.

The Board believes all of these matters require serious consideration even though they may not be directly related to this application. It would be desirable to establish a more effective liaison and communication plan between the local people, the two major plant operators, and the government departments and agencies. The Board plans to explore the possibilities of such a plan over the next few weeks.

7 DECISION

The Board is prepared to amend the existing approval to permit the modifications applied for, subject to the approval of the Minister of the Environment, the Minister of Energy and Natural Resources, and the Lieutenant Governor in Council. The form of the approval will be deferred until after the Board has completed its assessment of the emission administration system and issued its addendum report.

DATED at Calgary, Alberta, on 4 October 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

V. E. Bohme, P.Eng.
Board Member

N. Strom, P.Eng
Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Syncrude Canada Ltd. (Syncrude) F. M. Saville, Q.C. D. A. Holgate	**Technical Panel** A. W. Hyndman, P.Eng. J. E. Clark, P.Eng. G. W. Pool A. G. Gordon J. J. Barr **Environmental Panel** A. W. Hyndman, P.Eng. J. E. Clark, P.Eng. Dr. D. Leahey Dr. R. B. Canton R. V. Portelli, P.Eng. D. L. Dabbs D. C. Thompson
Fort McKay Indian Band (Band) A. Cullingham G. Bethell J. Brisebois	**Fort McKay Panel** Chief D. McDonald V. McDonald E. Lacorde F. Orr R. Grandjambe C. Harpe (translator) L. Redcrow (translator)
McMurray Manufacturers Association A. W. Taylor	
Fort McMurray Chamber of Commerce D. McAllister T. Mason	
Alberta Trapper's Association J. Rogers	
Alberta Environment J. Defir, P.Eng. S. Dobko, P.Eng.	
Energy Resources Conservation Board staff C.J.C. Page D. M. Bannister, P.Eng. R. G. Evans, P.Eng. D. Fraser Dr. R. N. Houlihan, P.Eng. Dr. H. F. Thimm	

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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NEW FACILITIES AT THE SYNCRUDE MILDRED LAKE OIL SANDS PLANT SO_2 EMISSION LIMITS

Addendum to Decision D 84-24
Application 840142

1 INTRODUCTION

In its Decision Report D 84-24, the Energy Resources Conservation Board (Board) approved the proposed new facilities at the Syncrude Mildred Lake oil sands plant, but deferred finalizing the specification of sulphur dioxide (SO_2) emission limits and issuing an approval. The Board's view was that the SO_2 limits to be specified in the permit were primarily an administrative matter, however, it recognized the importance of arriving at an arrangement that would be appropriate for the operator, the regulators, and the people in the area.

2 SO_2 EMISSION LIMITS

2.1 Applicant's Views

Syncrude Canada Ltd. (Syncrude) applied for a 90-day rolling average SO_2 emission limit of 265 tonnes per day (t/d) in place of the current daily limit of 292 t/d, in addition to continuation of the current hourly limit of 16.4 tonnes. It contended that environmental concerns would be adequately protected by a limit based on a 90-day rolling average and that the 265 t/d was required because of day-to-day variation in the sulphur content of bitumen feed, operational problems, and differences between design expectations and actual performance.

Syncrude testified that its new facilities would be designed for an SO_2 emission level of 229 t/d, based on a 99 per cent recovery efficiency in the sulphur plant with the hydrocracker operating. If the hydrocracker were shut down and sulphur recovery was 98* per cent (the level applied for) emissions would increase to 265 t/d. Syncrude requested that, although average annual emissions would be significantly less than the 265 t/d proposed limit, the permit limit should be set at a level which it could consistently meet. Syncrude accepted that the 90-day rolling average emission limit should include both main stack and flared emissions, and stated that it could operate within the present permit daily emission limit. Syncrude also pointed out that the measurement of emissions involved monitoring several complex parameters that were difficult to measure, and that normal engineering constraints on such equipment would limit the confidence in the final calculated emissions to ± 20 t/d.

Syncrude stated that the purposes behind daily or longer-term main stack SO_2 emission limits are related to long-range transport and acid deposition rather than local fumigation. Because acid deposition is affected by average emissions over an extended period, Syncrude claimed that it would be appropriate to control SO_2 emissions over a reasonably long measurement period. Syncrude noted that regional air quality is adequately protected because the stack height attenuates the local effect of emissions and, in any event, the local environment is protected by ground level ambient air quality limits which are set at a level to preclude damage. Syncrude believed that the hourly SO_2 emission limit of 16.4 tonnes is an adequate short-term limit and that it effectively sets a maximum on emissions in any single day. Studies conducted under the Alberta Oil Sands Environmental Research Project and by Syncrude were submitted to demonstrate that local environmental damage had not occurred.

Syncrude suggested that if the 90-day rolling average concept presented serious problems for either Alberta Environment or the Board, it would be prepared to continue with the current daily emission control and also calculate the 90-day average for a test period. Following completion of that test, the results could be examined and a decision made.

2.2 Interveners' Views

The Fort McKay Indian Band (Band) noted that SO_2 emissions were predicted by Syncrude to decrease as a result of the new equipment to be added to the plant, and questioned the rolling average concept and the proposed limit. It argued that an emission limit of 265 t/d provides a more than adequate buffer and that the rolling average should not be necessary. The Band argued that long-range transport or acid deposition is not the only point of concern with SO_2 emissions.

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* Although Syncrude's objective is to achieve 99 per cent sulphur recovery efficiency when the Sulfreen unit is operating, it expects the annual sulphur recovery efficiency to be 98 per cent.

The Band expressed concern "that a 90-day rolling average limit would permit Syncrude, in a worst case scenario, to emit high levels of SO_2 on a daily basis and still remain within its licence level". With respect to the Syncrude proposal that the present hourly limit of 16.4 tonnes sets a maximum daily limit, the Band stated that a daily limit set on this basis was inappropriate since it would be substantially greater than the current daily limit. The Band referred to Syncrude's evidence that it could operate within the present daily limit and saw no reason why a daily limit should not be set in future.

The Band contended that its historical pursuits of hunting, fishing, and gathering had been impaired by the population growth and industrial development that had invaded the region, and that the health of Band members had declined.

2.3 Alberta Environment

Alberta Environment questioned the administrative feasibility of the 90-day rolling average. Presently, daily SO_2 emissions are monitored with a continuous stack emission monitor (CSEM) and checked by conducting manual stack surveys to determine compliance with daily and hourly limits specified in the Clean Air Licence. The manual stack survey is the only method used by Alberta Environment to verify the company's emission data if deemed necessary. Replacing the daily limit with the proposed 90-day rolling limit could possibly result in an interpreted daily limit of 393 tonnes (24 hours multiplied by 16.4 t/hour) which would not be acceptable to Alberta Environment.

Stack surveys are conducted for monitoring compliance with the short-term limit and also are used to calibrate the CSEM, but are not a practical tool for monitoring compliance with a longer-term limit such as the proposed 90-day rolling average.

2.4 Board's Views

The evidence presented at the hearing shows that historically SO_2 emissions fluctuate widely owing to complexity of the operation. Emissions depend on the sulphur in the bitumen, the amount of coke burning necessitated by coking operations, and the rate of throughput and stability of sulphur removal operations. The Board has reviewed how the factors which are generally beyond Syncrude's control interact by considering several cases which could result in SO_2 emissions exceeding the design level:

- sulphur in bitumen varies up to 5 weight per cent as compared to the design value of 4.5 weight per cent, and if encountered, would result in SO_2 emissions of 280 t/d at 98 per cent sulphur recovery,
- the Sulfreen unit is designed with a 98 per cent service factor and therefore the unit may be off-line 2 per cent of the time or approximately 7 days per year. When this occurs, sulphur recovery could drop to 96.5 per cent and emissions would be estimated at 287 t/d assuming design basis bitumen sulphur content. Should a Sulfreen unit shut-down coincide with a bitumen feed of high sulphur content, then SO_2 emissions would be 320 t/d, and
- the hydrocracker is designed with a 92 per cent service factor and when shut down, SO_2 emissions would be 257 t/d at design bitumen sulphur content and 98 per cent sulphur recovery.

In addition to the foregoing, SO_2 emission measurement uncertainty of ± 20 t/d can result in interpreted emission levels exceeding the present daily limit of 292 tonnes.

The Board accepts that operational upsets, maintenance necessities, and feed variations can cause SO_2 emissions to vary widely on a short-term basis. The Board believes that emission limits must allow for such variations provided they do not result in detrimental environmental impacts.

The basic question is the duration of the emission control period. Should it remain on a daily basis or should it be extended as proposed by Syncrude? If it remains on a daily basis, then allowance must be made for potential variations in emissions as identified previously. However, if a longer control period is selected, then the periodic variations would be averaged out with normal operations and the average emission control rate would be reduced.

The adoption of the 90-day rolling average emission limit would eliminate the problems of variation in daily emissions which are beyond Syncrude's control. However, the Board recognizes that a 90-day average approach may not be ideal from either the Band's or Alberta Environment's point of view. The Board believes that, providing suitable limits are established, each control period could be applied and would complement the other. As indicated previously, the daily limit would be set at a level that would provide for some of the possible events that have an impact on emissions. The 90-day average limit would be set at a lower level on the basis that those daily variations average out over the period. As such, it would provide a better measure of performance and would provide a basis for assessing any emissions in excess of the daily limit. This combined approach, which was suggested by Syncrude for a test period, could be applied for a 2-year period and then reviewed. The test period would also provide an opportunity to review the efficiency of the sulphur unit and the hydrocracker. For the 2-year test period following installation of the new equipment, the Board believes the daily emission rate should be 292 tonnes and the 90-day rolling average rate should be 265 tonnes.

The Board believes a similar emission control system should apply during the interim period prior to the operation of the new equipment. The current approval specifies an hourly limit of 16.4 tonnes and a daily limit of 292 tonnes. The Board's review of the operation of the plant indicates that the latter limitation may not be completely realistic for a single day due to measurement uncertainty and variations in operating conditions. On the other hand, the average daily emission over a 90-day period should be less than the 292 tonnes. Having regard for these factors, the Board believes that the daily limit during the interim period should remain unchanged but the approval should also limit daily emissions averaged over a 90-day period to 280 tonnes. Should there be exceedances in the daily emission limit during the interim period, they could be evaluated in relation to the daily average for the 90-day period.

Regarding emission limits for protection of the local environment, the Board believes that the existing permitted level of 16.4 tonnes of SO_2 per hour is appropriate and should be retained.

3 DECISION

Having regard for its findings and its responsibility under the Oil Sands Conservation Act, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to revise Approval 2959. The approval would be in the form set out in Appendix A and would be subject to the terms and conditions therein contained and such other conditions as may be imposed by the Minister of the Environment as it affects matters of the environment, and the Associate Minister of Public Lands and Wildlife as it affects land and resources that are the property of the Crown in the right of Alberta.

DATED at Calgary, Alberta, on 21 December 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

V. E. Bohme, P.Eng.
Board Member

N. A. Strom, P.Eng.
Board Member

APPENDIX A — FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Her Majesty the Queen in the Right of the Province of Alberta as represented by the Minister of Energy and Natural Resources, Alberta Energy Company Ltd., Canada-Cities Service, Ltd., Esso Resources Canada Limited, Gulf Canada Resources Inc., HBOG - Oil Sands Limited Partnership, PanCanadian Petroleum Limited, Petro-Canada Exploration Inc. and Petrofina Canada Inc. for the recovery of oil sands, crude bitumen or products derived therefrom

AMENDMENT OF APPROVAL NO. 2959F

(Amending Approval No. 2959)

The Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter O-5.5 of the Statutes of Alberta, 1983, and with the approval of the Lieutenant Governor in Council, numbered and dated , hereby orders as follows:

1. Board Approval No. 2959 is amended.

2. The fifth paragraph of the preamble is amended by striking out "Appendices C, D, F, G, H and J" and by substituting "Appendices C, D, F, G, H, J, K and L".

3. Clause 1, subclause (1) is amended by adding

    (j) an application dated 9 February 1984 and supporting material marked as exhibits and evidence addressed at the hearing of the application,

4. Clause 2 is amended by striking out "7 507 000 cubic metres of synthetic crude oil" and by substituting "8 000 000 cubic metres of synthetic crude oil, plus 370 000 cubic metres of naphtha product".

5. Clause 4 is amended by striking out subclauses (d) and (f) and by substituting the following:

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* This is only a form of amendment of approval. The amendment of approval, when issued, may have minor variations from that set out here.

(d) results in the recovery of not less than 93.5 per cent of the crude bitumen contained in the oil sands processed by the extraction plant,

(f) results in the recovery in the form of elemental sulphur of,

(i) from the date of this approval, not less than 95 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant during each three-month period beginning 1 January, 1 April, 1 July or 1 October, and

(ii) from 1 January 1988, or such other date as the Board may stipulate, not less than 98 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant during each three-month period beginning 1 January, 1 April, 1 July or 1 October.

6. Clause 15 is amended by striking out "8.2 tonnes in any half-hour period (4.1 tonnes equivalent sulphur)" and by substituting "16.4 tonnes in any one-hour period (8.2 tonnes equivalent sulphur)".

7. The following clause is added after clause 15:

15.1 (1) The emission of sulphur dioxide, and the sulphur dioxide equivalent of other sulphur compounds, to the atmosphere from the plant incinerator and boiler stack and from all flare stacks shall not exceed,

(i) from the date of this approval, 280 tonnes per day (140 tonnes per day equivalent sulphur) calculated on a rolling average basis for that day and the previous 89 days, and

(ii) from 1 January 1987, or such other date as the Board may stipulate, 265 tonnes per day (132.5 tonnes per day equivalent sulphur) calculated on a rolling average basis for that day and the previous 89 days.

(2) Notwithstanding subclause (1), two years after the Sulfreen unit has been in operation, the Board shall review plant performance and may reduce the permitted sulphur dioxide emission limit to an appropriate level.

8. Clause 17, subclause (1) is amended by striking out "eight stack surveys" and by substituting "six stack surveys".

9. Clause 17, subclause (2) is struck out and the following is substituted:

(2) Syncrude shall summarize the results of each stack survey required by subclause (1) and forward them to the Board as soon as they are available.

10. Clauses 19 and 20 are struck out and the following are substituted:

19. (1) Three months after start of construction of the facilities described in the application dated 9 February 1984, and thereafter on a quarterly basis until completion of construction, Syncrude shall report the progress of construction to the Board.

(2) Prior to the commencement of the operation of the facilities described in the application dated 9 February 1984, Syncrude shall file with the Board the following details of the project design and operating procedures:

(i) process and instrument diagrams for all sections of the plant,

(ii) detailed material balances for all sections of the plant,

(iii) operating procedures including normal and emergency start-up and shut-down, and

(iv) other details as the Board may require.

(3) Upon satisfactory operation of the facilities and prior to 31 December 1989 or such later date as the Board may stipulate, Syncrude shall file with the Board complete details of any modifications made to the process design and operating conditions in the same detail as required by subclause (2).

20. Mining beyond the 25-year mine area outlined in Appendix A is not approved.

21. This approval expires on 31 December 2013.

22. Board Approval No. 1920 is rescinded.

11. Appendices K and L hereto attached are added to this order.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom
Board Member

APPENDIX K TO APPROVAL NO. 2959

Department of Energy and Natural Resources

MINISTERIAL APPROVAL

No. ERCB

Edmonton, Alberta

Pursuant to section 14 of the Oil Sands Conservation Act, I, Don Sparrow, Associate Minister of Public Lands and Wildlife, hereby approve Application No. 840142 dated 9 February 1984 from Syncrude Canada Ltd. to the Energy Resources Conservation Board in the matter of an amendment to Board Approval No. 2959 insofar as it affects land and resources that are the property of the Crown in the right of Alberta, such application to be granted by Amendment of Approval No. 2959F.

ASSOCIATE MINISTER PUBLIC LANDS AND WILDLIFE

APPENDIX L TO APPROVAL NO. 2959

Department of the Environment

MINISTERIAL APPROVAL

No. ERCB

Edmonton, Alberta

Pursuant to section 14 of the Oil Sands Conservation Act, I, Fred D. Bradley, Minister of the Environment, hereby approve Application No. 840142 dated 9 February 1984 from Syncrude Canada Ltd. to the Energy Resources Conservation Board in the matter of an amendment to Board Approval No. 2959 insofar as it affects matters of the environment, such application to be granted by Amendment of Approval No. 2959F.

Syncrude Canada Ltd. shall comply with the Clean Water Act Licence No. 83-WL-210, the Clean Air Act Licence No. 84-AL-057 or any subsequent amendments thereof, issued by the Department of the Environment.

MINISTER OF THE ENVIRONMENT

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

MANY ISLANDS PIPELINES (CANADA) LIMITED REQUEST FOR ADDITIONAL RESERVOIR DATA MEDICINE HAT MEDICINE HAT A AND C POOLS

Decision D 84-25
Application 840297

1 INTRODUCTION AND BACKGROUND

1.1 Application and Request for Additional Data

Many Islands Pipelines (Canada) Limited (Many Islands) submitted an application to the Board which raises an equity matter in a 7-township area of the Medicine Hat Field. Many Islands holds the natural gas rights to the Medicine Hat A Pool (A Pool) in the area of application. It contends that hydraulic fracturing during well stimulation in the underlying Medicine Hat C Pool (C Pool) has resulted in communication between the A and C pools, and that the C Pool wells are draining some of the A Pool gas reserves. In this report the aforementioned application will be referred to as the main application.

The main application included a request that the Board consider an order directing that certain additional reservoir data be obtained. The subject application relates only to the applicant's request for additional reservoir data. The specific information requested by Many Islands includes 8 interference tests conducted between pairs of closely spaced A and C Pool wells, and pressure build-up data on 102 C Pool wells which are each capable of producing over 2800 cubic metres per day and on 38 other C Pool wells.

1.2 Interventions

The major owners of the C Pool in the area of application, Merland Explorations Limited, Bralorne Resources Limited, and Gascan Resources Ltd. (Merland et al), intervened for the purposes of cross-examination and advancing argument, as did TransCanada PipeLines Limited (TransCanada).

1.3 Pre-Hearing Meeting and Decision

The Board held a pre-hearing meeting on 9 May 1984 to consider how and when to proceed with the various aspects of the main application. In a Memorandum of Decision, dated 15 May 1984, the Board concluded that the question of the need for additional data should be handled before considering the timing of subsequent hearing(s) on the remainder of the main application. The Board also indicated that if Many Islands decided to proceed with a request for additional data, and if the parties with a direct interest in the matter were unable to reach an agreement, then it would convene a hearing to consider the matter.

A hearing to consider the request for additional data was scheduled for 19 June 1984 and was cancelled at the applicant's request in a letter dated 12 June 1984. Many Islands subsequently advised the Board in a letter dated 28 June 1984 that an agreement on the taking of additional data could not be reached and asked that the Board re-schedule the hearing to consider the matter.

1.4 Hearing

The hearing regarding reservoir data commenced on 5 September 1984 and was adjourned on 7 September 1984 to await the filing of supplemental information. The hearing re-commenced and was completed on 14 September 1984. The panel sitting was G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and G. A. Warne, P.Eng. The participants are listed in the following table.

2 PROCEDURAL MATTERS

At the opening of the hearing Merland et al made a motion to exclude consideration of non-compliance with and rescinding of Informational Letter IL OG 75-9 (IL OG 75-9) for the area of application, and also the pre- and post-fracture pressure data submitted by the applicant on 31 August 1984 after the closing date for submissions. Merland et al stated that it had not had an opportunity to consider and respond to these two matters. After considering the Merland et al motion, the Board decided to proceed with the hearing and to consider the pre- and post-fracture pressure data, but only as it relates to the availability of data and not the interpretation of it. The Board was not prepared to consider non-compliance with or rescinding of IL OG 75-9 because notice was not given that these matters would be

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Many Islands Pipelines (Canada) Limited (Many Islands) W. T. Corbett	M. Melham J. D. Macgowan, P.Eng. I. Martin, P.Eng.
Merland Explorations Limited Bralorne Resources Limited Gascan Resources Ltd. (Merland et al) A. L. McLarty	
TransCanada PipeLines Limited (TransCanada) E.W.H. Mallabone P. J. Raina, P.Eng.	
Energy Resources Conservation Board staff M. J. Bruni H. R. Keushnig, P.Eng. A. Warren, P.Eng.	

considered. The Board added that it would deal with the question of compliance with IL OG 75-9 for the relevant reservoirs of southeastern Alberta outside of the hearing process in the normal course of its activities.

Merland et al, during its cross-examination of the applicant, made a motion that the hearing be adjourned because the application is incomplete and therefore premature. It submitted that the applicant intends to file with the Board additional studies which deal with the underlying foundation of the applicant's request for additional data. Merland et al contended that it had an opportunity to take issue only with what the applicant had put before the Board, and that the Board could not fairly rule on the application knowing the applicant intended to submit additional studies. The Board denied this motion for adjournment because, at the time of the motion, it had not heard all representations on Many Islands' request for additional data and it believed it might receive sufficient information during the hearing to rule on the matter. The Board indicated that after all the evidence was heard it would be prepared to hear argument from any participant on whether or not there is sufficient information for the Board to reach a decision or on a motion to adjourn the hearing.

3 ISSUES

Prior to addressing the particular request for additional data, the Board believes that it should decide if the evidence placed before it is sufficiently complete to allow a decision on the reservoir data application, and if the parties who might be affected had reasonable opportunity to learn the facts and furnish evidence or argument relevant to the application.

If the Board decides the answers to both of the above questions are yes, it believes it should then deal with the following issues:

- Is there or is there not sufficient information before the Board for it to proceed to a hearing of the main application with a reasonable expectation of resolution?
- The type and amount of additional reservoir information required.
- The cost of obtaining any required additional reservoir information.
- The timing and procedures for obtaining any required additional reservoir information.
- The jurisdiction of the Board to direct the obtaining of additional information.

4 COMPLETENESS OF THE APPLICATION AND OPPORTUNITY OF AFFECTED PARTIES TO LEARN THE FACTS

The Board is satisfied that it can rule on the request for additional data with the evidence before it. It has reached this conclusion on the following basis:

- The Board believes that it is aware of essentially all pressure, production, and test data that have been gathered and are available in the subject area and it has the details of certain of this data.
- The applicant gave its interpretation and conclusions respecting some of the available data, its views on how the requested data would be used and why it believed the data were needed, and its opinion of possible costs to the C Pool owners of gathering the requested data.

Regarding the parties who might be affected, the Board is satisfied that those who intervened at the hearing had sufficient opportunity to learn the details of the application for additional data, to question the material, and to furnish evidence or argument respecting it.

5 INFORMATION BEFORE THE BOARD AND EXPECTATION OF A RESOLUTION OF THE MAIN APPLICATION WITHOUT ADDITIONAL DATA

5.1 Applicant's Views

Many Islands provided examples of data, data comparisons, and data interpretations to illustrate evidence of communication and drainage it observed from existing data. The specific areas of evidence include graphs comparing production rates and behaviour for adjacent A and C Pool completions; completion, stimulation, and segregation test details for two Many Islands' wells completed in both the A and C pools; comparisons of C Pool pressure data with A Pool pressures; material balance plots for the A Pool; comparison of C Pool cumulative production with reserves; and pre- and post-fracture pressures for certain C Pool completions.

Many Islands also filed supplemental information at the hearing: lists of logs, core and drill-stem test data examined; pressure/compressibility factors by township in the A Pool; A Pool material balance plots for townships surrounding the application area; and pressure versus time plots for quarter township blocks in the A Pool.

Many Islands, in response to questioning, said it is conducting additional studies that will be submitted when it requests a hearing of the main application. The studies presently underway involve geological evaluation, net pay mapping, and volumetric analysis of the A and C pools in the application area. Many Islands stated that a small amount of pressure data was received from C Pool owners after the application was submitted. It is incorporating this data into its studies. It is also reviewing data available from the City of Medicine Hat and other data in the public record, for possible inclusion in its studies.

Many Islands stated that the evidence filed with the application is based on the best data that it had at the time, and from this evidence it concludes that communication and drainage exists. However, it contends that additional data are required to complete the studies necessary to convince the Board of this and to arrive at possible remedies.

5.2 Merland et al Views

Merland et al, in final argument, contended that the Board could not come to even a preliminary conclusion regarding communication and drainage based on the evidence before it. It said the application lacks interpretation of the data presented, explanation for examples included and excluded, assessment of other factors such as operating methods and A Pool lateral migration, and complete studies of both the A Pool and existing data from adjacent areas. Merland et al stated that the applicant should complete its studies, and it may be that nothing more will be required.

5.3 Public Record

Two documents prepared by the Board staff were submitted at the hearing to assist the Board with its understanding of data available from the public record for the application area. The documents list about 206 wells and 543 pressures for the A Pool, 438 completions and 43 pressures for the C and D pools, 23 wells for which cores had been taken, the suite of logs available for each well, and a description of the production data available for each well.

5.4 Board's Views

With the additional data and studies identified at the hearing, it is difficult for the Board to conclude that more data are needed prior to setting the main application down for hearing. This is not to suggest, however, that the Board is certain it will be in a position to decide the main application without further test data. Rather, it reflects the conclusion that it is inappropriate to require a third party to gather special reservoir data for the use of the applicant, until the need for such data is clearly and definitely established. The need for such data in this instance was not clearly and definitely established and the Board is not prepared to approve the application by Many Islands to direct the gathering of additional reservoir data by the C Pool owners.

The Board now recognizes that it could have simply scheduled the main application for hearing upon its receipt earlier this year. It did not do so because at the time it was not aware of all the data that exists. Additionally, it believed there was a reasonable chance that the involved parties would agree to gather at least some data which could be beneficial in resolution of the issues raised in the main application. Such an agreement appears to have been close to realization but unfortunately was not achieved.

The Board recognizes that the problem before it is a unique and difficult one and that the more data available, the better the chance of a proper disposition of the matter. For this reason, it continues to support the idea that the involved parties should be negotiating towards the voluntary gathering of as much reservoir data that may be needed as is practical. It also intends to have its Gas Department review the test requirements set out in IL OG 75-9, and ensure that they are being satisfied and that all available data are filed with the Board in accordance with section 11.120 of the Oil and Gas Conservation Regulations.

6 REMAINING ISSUES

In view of the Board's finding above, the remaining issues need not be considered.

7 DECISION

The Board denies the application by Many Islands for an order directing the C Pool owners to gather additional test data. The Board is prepared to proceed to a hearing of the main application as soon as it is informed by Many Islands that the information it intends to submit in support of the application has been filed.

DATED at Calgary, Alberta, on 16 October 1984.

ENERGY RESOURCES CONSERVATION BOARD

GJDeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

L A Bellows

L. A. Bellows, P.Eng.
Board Member

G. A. Warne

G. A. Warne, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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SHELL CANADA RESOURCES LIMITED PEACE RIVER EXPANSION PROJECT

Decision D 84-26
Application 840498

1 INTRODUCTION

1.1 Application

Shell Canada Resources Limited (Shell) applied under section 10 of the Oil Sands Conservation Act for approval of a commercial scheme involving the expansion of Shell's current "Peace River In Situ Project" (PRISP) under Board Approval 2485. The "Peace River Expansion Project" (PREP) is designed to use a pressure cycle steam drive process to recover an average of 1600 cubic metres per day (m^3/d) of crude bitumen from the Peace River Bluesky-Bullhead Oil Sands Deposit in the area shown in Figure 1.

PREP would involve the drilling and production of 636 wells on 24 well pads through a series of three 10-year phases. The project would cost $200 million (1984 dollars) and create jobs for approximately 540 (peak) construction personnel and 115 operation and contract personnel.

1.2 Hearing

The application was considered at a public hearing held in Peace River, Alberta, on 11 and 12 September 1984, with N. A. Strom, P.Eng., L. A. Bellows, P.Eng., and F. J. Mink, P.Eng., sitting.

Those who appeared at the hearing are shown in Table 1.

1.3 Background

Shell and Shell Explorer Limited hold approximately 62 000 hectares (ha) of oil sands leases in the Bluesky-Bullhead formation in the Peace River area. As well, the Petroleum and Natural Gas rights to the base of the Bluesky-Bullhead zone are held on approximately 1300 ha.

Since 1962, Shell has conducted experimentation including steam soak, steam drive/drag, injectivity, and combustion tests. Physical model experiments were undertaken between 1972 and 1974 to evaluate and optimize well spacing and steam drive operations. The pressure cycle steam drive process resulted. The process is dependent on the presence of a thin basal water zone underlying the Bluesky-Bullhead bitumen-bearing formation, characterized by low bitumen saturation and high initial in situ permeability to fluids. The formation including the basal water zone is sealed above and below by shales of the Spirit River and Mississippian Debolt formations, respectively. The shale layers provide a seal such that pressure variations are contained within the formation in a local pattern area of injection. This allows development of a high pressurization phase through steam injection through an injection well followed by a steam drive, blowdown phase through surrounding producing wells.

PRISP began operation in late 1979 as an experimental joint venture of the Alberta Oil Sands Technology and Research Authority, Shell, Shell Explorer Limited, and Amoco Canada Petroleum Company Ltd. PRISP was designed to test the pressure cycle steam drive process in one fully confined 7-spot pattern and consists of 7 injection and 24 production wells arranged in seven 2.8-ha, 7-spot patterns. At PRISP, the first pressure cycle is completed and the second started. Shell is also conducting a multisoak test on a separate pattern to establish the impact of multisoaking prior to pressure cycle steam drive and to evaluate interwell interference effects.

Through history matching of laboratory and field data, Shell used physical and numerical models to develop a recovery process and operating policy for PREP. This led to the proposed expansion to commercial operation.

2 ISSUES

Although the Board recognizes many of the matters raised in evidence, it believes the major issues concerning the project are:

- Reserves and recovery efficiency
- Size and phasing of the project
- Environmental management
- Water management
- Field facilities and the protection of aquifers
- Marketing of bitumen

TABLE 1 THOSE WHO APPEARED AT THE HEARING

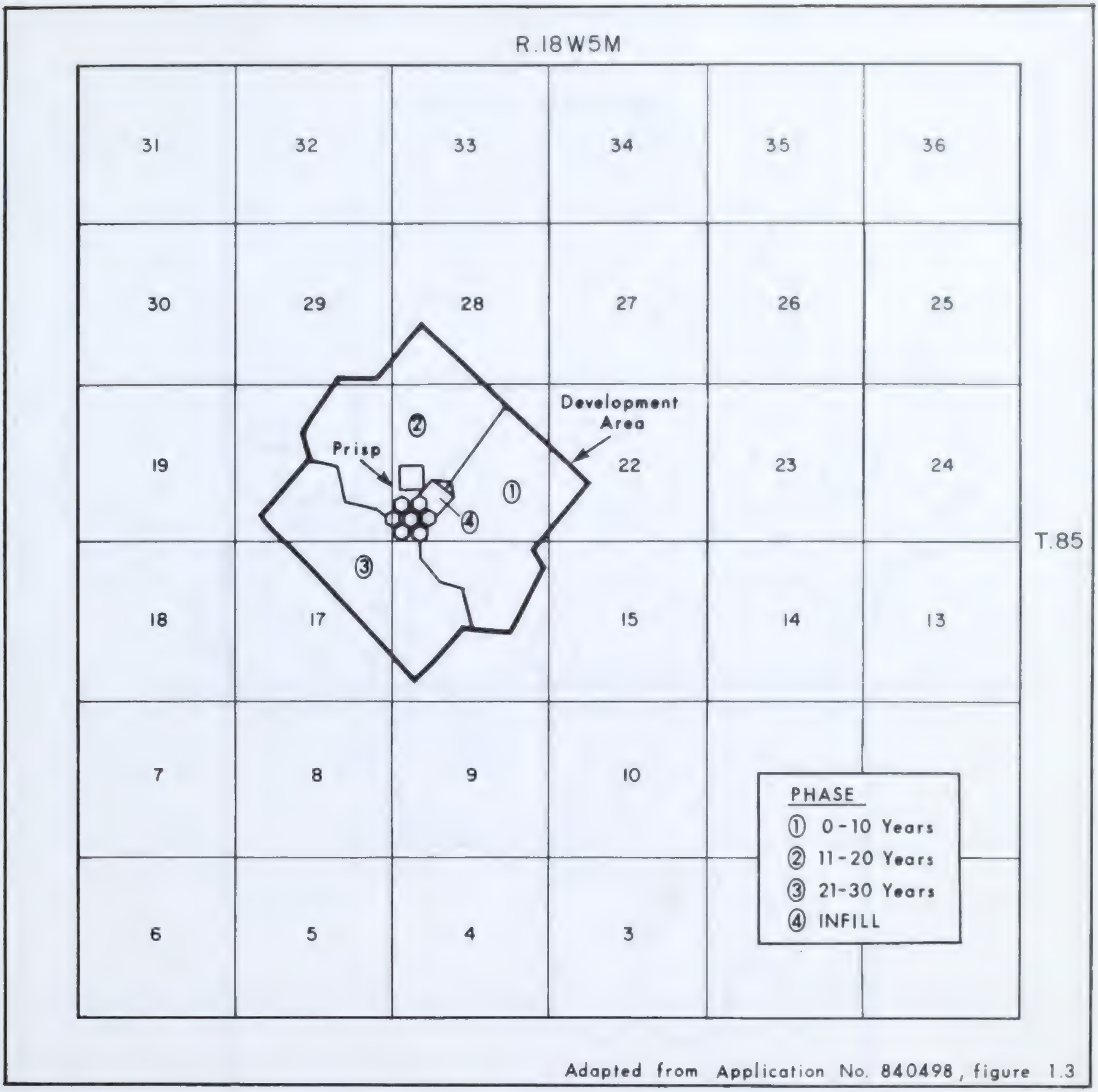
Principals and Representatives (Abbreviations used in Report)	Witnesses
Shell Canada Resources Limited (Shell) D. O. Sabey, Q.C. H. W. Lemieux	R. G. Gorrill, P.Eng. J.W.F. Klein, P.Eng. R. M. Wrubleski, P.Eng. B.R.D. Gerus, P.Eng. P. Kitzan, P.Eng. R. H. Lea, P.Eng. R. Webb M. Strong
BP Resources Canada Limited C. Gales	
Dome Petroleum Limited A. R. Fraser	
Lesser Slave Lake Indian Regional Council (the Council), Whitefish Lake Indian Band, Duncan's Band B. Martin J. Slavik	J. Badger R. Woolier E. Tallman J. Slavik
Lubicon Lake Band and Native Members of the Cree Community of Little Buffalo Lake (Lubicon Band) E. Peterson	E. Peterson
Mackenzie Regional Planning Commission R. Roycroft	
Alberta Environment G. Roy	
Energy Resources Conservation Board staff H. R. Hansford R. G. Evans, P.Eng. S. L. Sills, P.Eng. I. M. Cameron, P.Eng. R. M. Feick	

- Availability of diluent
- Socio-economic impact
- Local employment and business opportunities for Natives

3 RESERVES AND RECOVERY EFFICIENCY

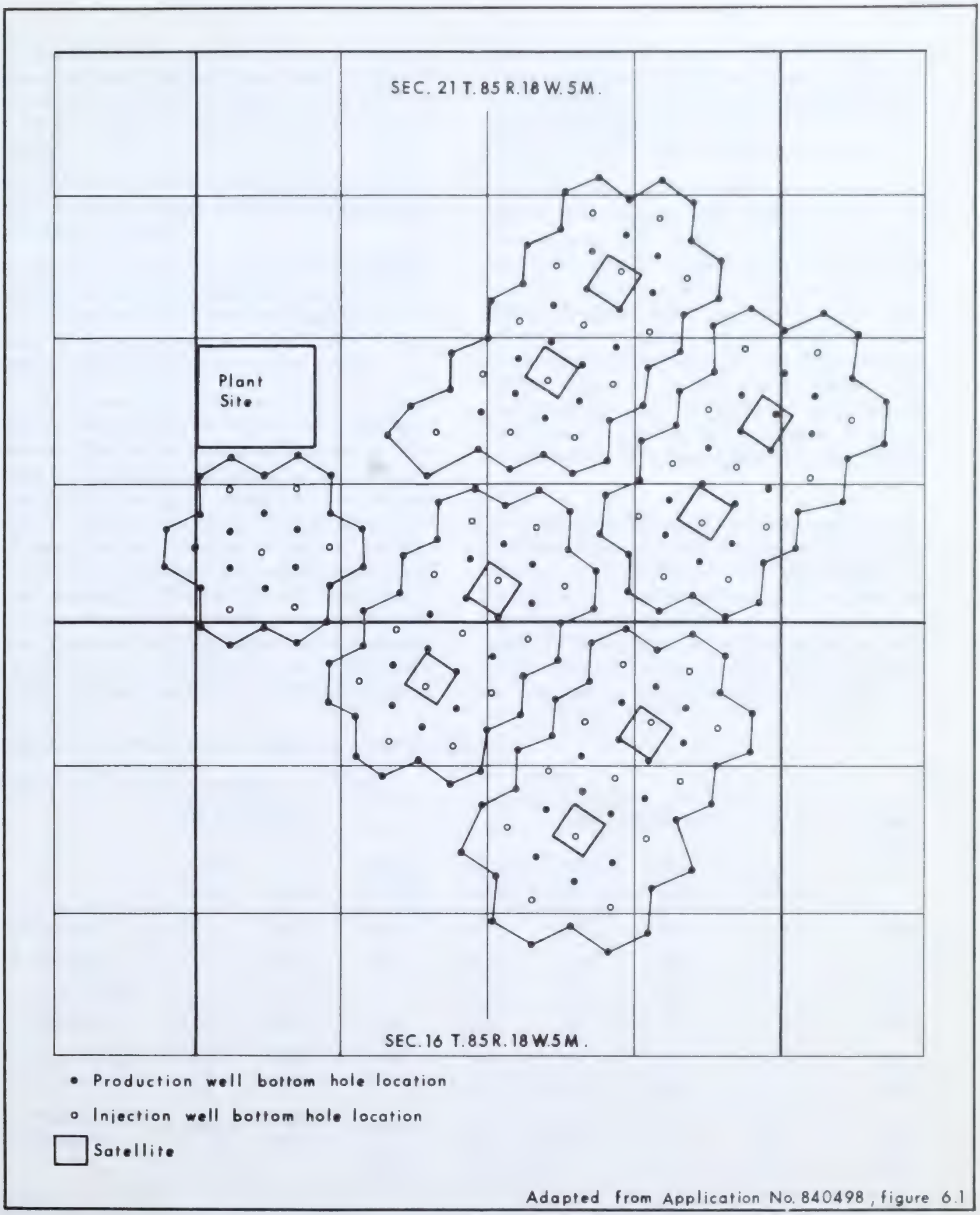
Shell submitted that the Bluesky-Bullhead formation in the area of application is an evenly-grained sandstone deposit of relatively consistent vertical and lateral uniformity. Net sand thickness averages 25 metres (m) and the average bitumen saturation is 77 per cent of the pore volume.

In Phase 1 of PREP, wells would be arranged in four clusters, each consisting of 2 satellite pads, 13 injection wells, and 40 production wells as shown in Figure 2. To calculate in-place reserves, Shell stated that it included a 50-m buffer zone around each of the well clusters to arrive at a project development of 630 ha for the three phases. The corresponding in-place reserve was calculated to be 32 million (10^6) m^3. After history matching the first pressure cycle performance at PRISP to its numerical simulation, Shell extrapolated the results



Adapted from Application No. 840498, figure 1.3

FIGURE 1 SHELL CANADA RESOURCES LIMITED PEACE RIVER EXPANSION PROJECT.


SEC. 21 T. 85 R. 18 W. 5 M.
Plant Site
SEC. 16 T. 85 R. 18 W. 5 M.
● Production well bottom hole location
○ Injection well bottom hole location
☐ Satellite

Adapted from Application No. 840498, figure 6.1

FIGURE 2 WELL AND SATELLITE LAYOUT - PHASE 1

through two subsequent pressure cycles. It submitted its production versus time prediction as shown in Figure 3. A bitumen recovery for the project of 17.6 x 10^6 m^3 or 55 per cent of the bitumen in place (BIP) was predicted.

Shell also noted that the recovery at PRISP after one pressure cycle was 17 per cent of BIP enclosed within the pattern boundaries.

The Board is in general agreement with Shell's geological description of the Bluesky-Bullhead formation. It notes that the consistent vertical uniformity and lateral continuity in the development area should allow optimal performance of the proposed recovery process.

The Board notes that the PRISP experience to date has played an integral role in the design of PREP. The Board also notes that pressure cycling at PRISP was not preceded by multisoaking and that at the time of PREP design, PRISP had just completed its first pressure cycle. On the basis of a 630 ha development area and 480 production wells within the development area, the in-place reserve associated with each production well would average 72.9 thousand (10^3) m^3. From Table 2, it is seen that at the conclusion of the first pressure cycle, cumulative recovery for each well as an average is expected to be 17.4 x 10^3 m^3 or nearly 25 per cent of BIP. The Board observes that actual PRISP experience had demonstrated 17 per cent of BIP for enclosed well patterns after one pressure cycle. Evidently a difference between PRISP and PREP is that the multisoak in PREP is expected to generate an additional 4.9 x 10^3 m^3 or 7 per cent of BIP prior to the pressure cycles.

The Board notes that PREP is based on achieving a closed steam-chamber effect during the action of pressuring-up each cluster. The Board is satisfied that on the strength of PRISP experience this can be achieved. The result should be a comparatively efficient transmission of heat into the progressively higher sections of the reservoir. Indeed, the early PRISP experience lends considerable confidence to projecting recoveries beyond 30 per cent of BIP. The completion of the second pressure cycle at PRISP will provide a much better basis for verifying Shell's projection of recovering some 36 x 10^3 m^3 per typical well over a 10-year period.

Recognizing the importance of the time-rate-cumulative recovery projections to the overall project planning and economics, the Board believes that the submitted performance projections should be carefully reviewed and compared at the completion of the second pressure cycle at PRISP. This would occur about year-end 1985. In the meantime, the Board would accept the projections as submitted by the applicant as shown in Table 2.

TABLE 2 TYPICAL WELL PRODUCTION FORECAST

Exerpt from Table 4.1, Application No. 840498

	Oil Production				**Water Production**			**Total Calendar Days**
	PDOR[1] (m^3/d)	Time (days)	Volume (10^3 m^3)	CDOR[2] (m^3/d)	WOR[3] (m^3/m^3)	Rate (m^3/d)	Volume (10^3 m^3)	
1st Multisoak	24	60	1.4	10.7	3.3	80	4.8	135
2nd Multisoak	21	170	3.5	15.7	3.8	80	13.6	225
1st Pressure B.U.	6.5	243	1.6	5.8	9.1	60	14.5	270
Blowdown	15.0	729	10.9	13.5	2.3	35	25.3	810
2nd Pressure B.U.	7.8	243	1.9	7.0	9.1	71	17.2	270
Blowdown	12.5	729	9.1	11.3	2.3	29	21.2	810
3rd Pressure B.U.	6.8	243	1.7	6.1	9.1	63	15.3	270
Blowdown	7.3	774	5.7	6.6	2.3	17	13.2	860
			35.8	9.8			125.1	3650

NOTES:

1. PDOR: Production Day Oil Rate - Oil Volume/Production Days.
2. CDOR: Calendar Day Oil Rate - Oil Volume/Total Days of the Cycle.
3. WOR: Water/Oil Ratio.

4 SIZE AND PHASING OF THE PROJECT

Shell stated that PREP could be the first of a series of possible expansions. Future incremental additions would be dependent on the technical success of PREP and other factors such as bitumen markets and oil price. Therefore, Shell proposed that PREP be considered as a stand-alone application and the terms of approval not make provisions for possible further expansion.

PREP would be constructed around the existing pilot operation in three development phases (Figure 1), each of 10 years duration. Shell requested approval for a 30-year project recovering an average of 1600 m^3/d of crude bitumen. It recognized that facilities for Phases 2 and 3 would be needed at year 10 and 20, respectively, and agreed to submit field development plans to the Board for its review and approval as deadlines for those phases approached.

Shell viewed the scheduling of pressure cycles as an integral part of project operations in order to minimize pressure interference between wells and optimize utilization of steam generation capacity. In Phase 1 of PREP, each well cluster would be separated from another by approximately 100 m. Shell stated that during a pressure cycle, one cluster would be in the pressurization phase and the remaining three clusters would be in the blowdown phase. The 100-m space between clusters would be necessary to minimize interwell interference between clusters under different operations.

Shell filed field development details for Phase 1 and indicated that experience would be the basis for changes that may be implemented in Phases 2 and 3.

The Board recognizes that development plans for Phases 2 and 3 may vary depending on experience gained by the remaining pressure cycles at PRISP and the first phase of PREP. Accordingly, the Board would require as a provision of its approval that Shell submit details of Phases 2 and 3 to the Board for its review and approval prior to the commencement of construction of those phases.

5 ENVIRONMENTAL MANAGEMENT

Shell submitted a detailed assessment of the biophysical impact of PREP on the region. It noted that the project is confined to land consisting largely of muskeg with limited or no agricultural potential or other renewable resource use applications. Notwithstanding the setting, the project is designed to limit the adverse impacts on air and water quality. Stack design for PREP would ensure that gaseous emissions of sulphur dioxide (SO_2) and nitrogen oxides (NO_X) are well within provincial standards prescribed by the Clean Air Act and Regulations.

The Board is satisfied that the mitigative measures proposed by Shell would limit atmospheric emissions and meet provincial standards during normal operating conditions. The Board notes that the low levels of SO_2 emissions forecast from PREP and the high to moderate buffering capacities of soil should prevent any measurable impact on soil or water bodies in the project area. In general, the Board believes Shell's environmental management program respecting emissions and monitoring is satisfactory.

6 WATER MANAGEMENT

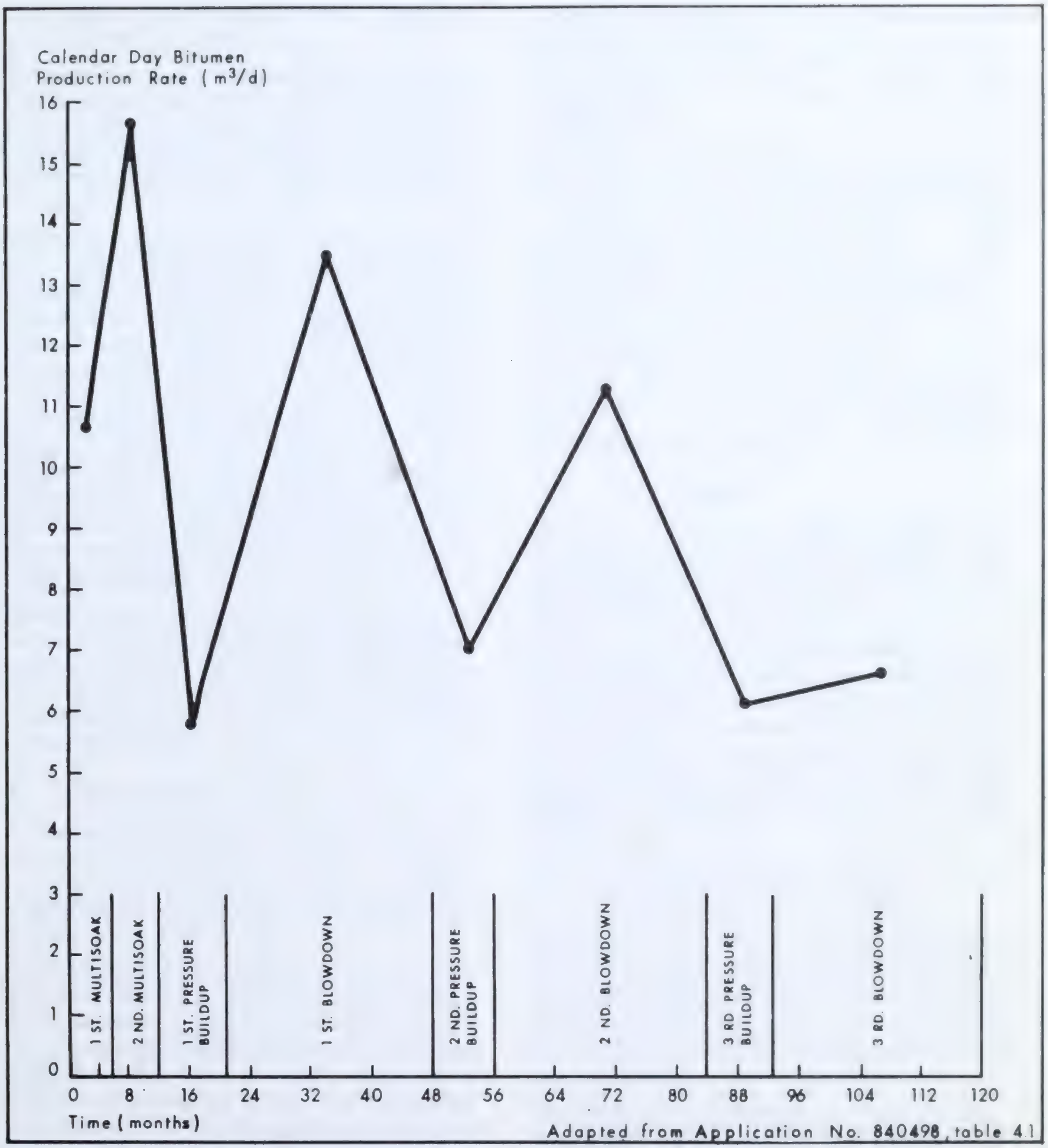
6.1 Water Supply

Shell proposed to fulfill requirements for PREP by continuing to use the present licence volume of 3600 m^3/d from Cadotte Lake, currently dedicted to PRISP, and an additional volume of 4100 m^3/d from the Peace River. Shell stated that Cadotte Lake could not provide the total PREP water requirements without major impact on lake levels during any dry periods and no future increase in withdrawal rates was planned. Shell built in a contingency plan for any possible restriction on the availability of water for industrial purposes from Cadotte Lake by applying for its total PREP requirements in its application to withdraw water from the Peace River that is presently before Alberta Environment.

Shell stated that the original approval for water withdrawal from Cadotte Lake was based on water needs for PRISP. Shell further stated that, at that time, no assessment of the replenishment rate of Cadotte Lake was made.

Shell stated that maximum PREP water requirements from the Peace River would be less than 0.02 per cent of the lowest recorded flow. Thus Shell saw no constraints on river withdrawal rates for PREP. The water intake system would incorporate equipment to accommodate future expansions, including additional lines installed from the river to the pump suction chambers within the pump station. Shell viewed the pipeline from the Peace River to the PREP site to be the largest incremental cost in any expansion of the water source. It indicated that consideration was being given to sizing the water supply pipeline so that it could meet a bitumen production rate of 6400 m^3/d.

The Lubicon Band requested that water removal from Cadotte Lake be discontinued upon availability of a Peace River water supply. Its concern was not based on any evidence that the licensed water withdrawal rate was the cause of undesirable ecological changes but rather that the inherent natural cyclic variations of the lake system could have long-term effects on the regional water supply. The Lubicon Band stated that if industrial water



Adapted from Application No. 840498, table 4.1

FIGURE 3 TYPICAL WELL PRODUCTION FORECAST

removal was eliminated as a variable, only the relatively unknown natural variations would remain and stresses on the lake would be reduced.

The Board accepts the evidence presented that there were no apparent adverse effects from low water levels of Cadotte Lake during recent dry years. It notes that the existing water withdrawal permit prevents Shell from excessive water withdrawal from Cadotte Lake in critically low periods.

While the Board accepts Shell's view that the present project is unlikely to have an adverse effect on the water regime in the area, the Board finds that there is limited information available on the relationship of near-surface waters to actual surface bodies of water to show the effects conclusively. It believes, therefore, there is a need to conduct studies of the regional groundwater supply. This may be of particular importance in future if Shell proposes to increase its project production to 6400 m^3/d. The Board notes this limitation and encourages Alberta Environment and the applicant to review and promote investigations into regional groundwater and surface water hydrology systems relating to the areas identified by the Lubicon Band.

With the proposed access to Peace River and ready expansion of it as a water supply, the Board believes that, should any problems arise with water withdrawal from Cadotte Lake, consideration should be given to using Peace River to fulfill all water requirements for PREP and any future projects.

6.2 Produced Water Reuse

As designed, there would be no treatment or reuse of produced water from PREP. However, Shell proposed to conduct a development program and sponsor research of technology aimed at the reuse of not less than 30 per cent of produced water by 1990.

Shell acknowledged that optimizing the reuse of water in its process was in the overall public interest. It stated that lime treatment technology approved for Esso's Cold Lake project is accompanied by the production of waste sludge. Since Shell would anticipate producing about three times as much sludge as Esso based on produced water volumes and a higher water-bitumen ratio, it concluded that the problem in the handling of the higher volume of by-product sludge would be unacceptable for its project.

Shell stated that investigations to develop alternate water reuse technology other than lime treatment would begin during 1985 with a laboratory and bench-scale pilot program. The program would include a study on the toxicity of lime sludge from produced water. Shell proposed to conclude the laboratory work in 1985 and begin a field pilot project in 1986, should a suitable technology be identified. Shell indicated that 1990 is its target date for commercial installation assuming the technical success of pilot work.

The Board endorses Shell's aggressive approach in developing water reuse technology compatible with the recovery process employed at Peace River. The Board notes that Shell has alluded to the possibility of future expansions beyond PREP and believes that if development expands, water reuse will become increasingly important. Studies to develop a suitable technology should be undertaken early in the project life for application as quickly as possible. The Board would require annual reports to be submitted by Shell describing the progress of its on-going investigations. As well, approval of the selected water reuse process would be required.

6.3 Water Disposal

In a manner similar to that employed at PRISP, Shell proposed to dispose of produced water and other waste waters by deep well injection into the Devonian Leduc D-3 reef near the project area.

Subject to the objective of optimum water reuse, the Board finds that Shell's proposal for produced water disposal is acceptable. The Leduc D-3 formation in the area is extensive and does not contain potable water or usable hydrocarbons and thus would not be damaged by the disposed fluids. The specific details of the disposal system are addressed in a separate water disposal application to the Board.

7 FIELD FACILITIES AND THE PROTECTION OF AQUIFERS

The proposed PREP field development would include pad areas containing wellheads, pumpjacks, and production satellite facilities. In Phase 1, wells would be directionally drilled from eight pads, each consisting of 26 or 27 wells. Shell noted that grouping field facilities at pad areas minimized surface disturbances.

Shell did not foresee any problems associated with directional drilling or well completions. During the summer of 1984, Shell drilled four directional wells to evaluate this method of field development as well as to test the feasibility of using nitrogen-foamed cement to anchor the casing and protect the subsurface environment. Shell stated that the tests proved successful and no problems were encountered. Shell was confident that nitrogen cement would maintain its integrity at expected injection temperatures.

Shell is presently investigating casing thread compounds for application at PREP wells. It recognized that the selected thread compound should maintain a good seal at steam injection pressures of about 11 000 kilopascals and temperatures up to 380°C. Shell undertook to provide the Board with details of the thread compound when the final selection was made.

Shell stated that a potassium chloride (KCl) mud system was chosen for the drilling of PREP wells. Drilling liquids would be trucked to off-site pits, clarified, and recycled into drilling operations or injected down deep wells while solids would be hauled to a separate pit and buried. Shell confirmed that spray irrigation techniques would not be employed as a disposal method.

Shell stated that near surface groundwater appears to exist in the PREP area. The characteristics and extent of near-surface waters was not fully known and Shell had not undertaken its own studies to determine those characteristics. Shell believed that due to the high iron content of near-surface waters, little use could be made of it either as potable water or a water source for PREP.

The Board is satisfied that the drilling procedures outlined by Shell are adequate to ensure the integrity of directional wells at PREP. Shell would be required to submit to the Board details of the thread compound to be used at PREP. The Board is satisfied that KCl mud can be disposed of in an environmentally safe manner.

8 MARKETING OF BITUMEN

In its submission, Shell stated its intent to initially market the diluted bitumen stream to northern tier refineries in the United States. Shell characterized this market region as providing significant potential for increased bitumen exports based on an assessment of the competitive position of Canadian-produced bitumen with respect to comparable Mexican heavy oil blends. Shell estimated this market potential to be approximately 30 000 m^3/d greater than the present level of heavy oil exports and expressed confidence that these market conditions would prevail well into the future.

The Board accepts Shell's assessment of the available market and, subject to continuation of the existing price structure and market access, it does not expect marketing to impose a constraint on the viability of the project.

In light of the trend towards declining conventional crude oil production in Canada, Shell believed that in the long term, synthetic crude oil markets will provide greater potential than diluent bitumen markets. For this reason, Shell stated that it intends to closely examine the feasibility of constructing a bitumen upgrader if field expansion is planned.

Shell indicated that the preferred site for an upgrader would be at its Scotford refinery complex near Edmonton to allow Shell to take advantage of the complementary nature of the two facilities. In the current economic environment, Shell believed that, at best, upgrading projects are marginally economic and that the low level of production from PREP does not justify a decision to construct an upgrader at this time.

9 AVAILABILITY OF DILUENT

Shell submitted that approximately 800 m^3/d of pentanes plus would be required to dilute the produced bitumen stream to pipelining specifications, and estimated that 20 truck trips per day from a source in the Fox Creek area would satisfy this requirement.

Shell stated that in the absence of future upgrading capacity, there was a significant likelihood that a diluent shortage could emerge in the early 1990s. Discussions between Shell and the Alberta Petroleum Marketing Commission confirmed Shell's understanding that the pentanes plus supply for bitumen diluent use has priority status third only to the Bowden refinery and Alberta petrochemical plants. With this understanding, Shell was prepared to discount the prospect of an administered allocation scheme becoming necessary into its commercial risk assessment of PREP. Shell suggested that alternatives were available to extend the diluent supply. Among these were:a reduction in the diluent/bitumen blend ratio when ambient temperatures permitted; the repatriation of pentanes plus presently exported; or the use of light streams from refineries located in Edmonton. For the above reasons, Shell does not expect diluent supply to be a constraint on project viability.

The Board is satisfied that sufficient volumes of pentanes plus are available to meet requirements in the early years of the project. However, the Board expects that in light of the current and potential rate of development of bitumen recovery projects, the issue of diluent availability will assume increasing significance over the next few years. Given that Shell has accepted as a commercial risk the need to secure diluent, the Board is satisfied that approval of this project should not be conditioned on perceived shortages in the long term.

10 SOCIO-ECONOMIC IMPACT

10.1 Economic Impact

Shell submitted that, based on its understanding of the project's commercial terms and its current projections regarding product price, the project would be economically viable.

Subject to further confirmation of operating performance projections as discussed in Section 3 of this report, the Board agrees with the assessment and is satisfied that a positive financial return would be generated by the project investment.

Shell indicated that the project capital costs would amount to some $200 million[1] during the 18-21 month construction period, and that operating costs would be approximately $50 million per year. Shell anticipated that 70 per cent of the capital and 90 per cent of the operating expenditures would be made in Alberta. Shell expected that $12 million would be earned by local residents during the construction phase and that $10 million per year would accrue to the region through wages, goods and service purchases, and property taxes during operations.

At the provincial level, Shell identified four monetary streams as contributing to the total direct impact. In addition to expenditures made in Alberta during the construction and operations phase, Shell included provincial royalties and taxes, a portion of profits which was assumed to be reinvested in Alberta, and a requittal of 8 per cent of federal taxes. The sum of these components amounts to a total direct monetary impact of $2400 million on the Alberta economy. Using a multiplier of 2, Shell estimated that the total direct and indirect impact would be $4800 million. According to Shell, the net benefit to Alberta would amount to $600 million, a figure which was derived by summing royalties, taxes, and the portion of profits assumed to be reinvested.

Based on the evidence, the Board is satisfied that a significant monetary impact on the province would result from project expenditures and its measurement of this impact differs from Shell's only to the extent noted below.

The Board views federal taxes as representing a tangible benefit to be shared by all Canadians, including Albertans, and considers this benefit to be a part of the indirect provincial impact. However, the Board does not believe that the payment of federal taxes will result in a proportionate requittal to the province of origin and therefore has excluded this component from the direct provincial impact.

In addition, the Board does not regard an assumed level of profit reinvestment as an appropriate addend in the monetary impact. As in previous decisions, the Board believes that the impact of project profits in Alberta will be felt only to the extent that Albertans are shareholders of the project sponsors. Accordingly, the Board has chosen to recognize this impact on the basis of shareholder distribution. For this purpose, the Board has assumed that 2 per cent of the shareholders of the project sponsors reside in Alberta.

Having regard for the foregoing, the Board has estimated a net provincial benefit of $444 million associated with the project and a direct monetary impact of $2190 million. Using a multiplier of 2, the Board estimates that a total direct and indirect impact of $4380 million would result from the project. The Board notes that to the extent materials are procured from Canadian sources outside of Alberta, and recognizing the value of federal tax payments, the direct national impact will be larger than $2190 million.

Table 3 compares the provincial monetary impact and project benefits submitted by Shell with those recognized by the Board.

10.2 Social Impact

Shell submitted an assessment of the regional social impact based on its estimate of the required work force during construction and operation. According to Shell, an average construction work force of 300, with a peak of 540, would be required. Based on the experience of PRISP, Shell estimated that one-third of this requirement would be filled by residents of the Peace River Region. During the operations phase, Shell submitted that 115 new positions would be created, of which 50 are expected to be filled by local residents. Shell anticipated that these labour requirements would have a minimal impact on regional housing demand during construction since the workers would be housed in a construction camp. During operations, Shell estimated that the regional population would increase by approximately 150 individuals. Shell indicated that the housing requirements of these individuals could be readily accommodated in view of the existing large surplus of housing available in the region. With respect to the demand for public facilities and services, Shell indicated that the most substantial impacts during construction would be on recreational facilities, health care installations, and police services. During operations, Shell submitted that local schools would be the major community facility affected and that elements of the school system were currently examining the need for expanded facilities. Shell stated that it intends to keep local authorities advised of the labour force composition so that the potential for stress on the existing infrastructure can be more readily identified.

The Board is satisfied that Shell adequately addressed the prospects for social impacts arising from PREP. Further, the Board agrees that Shell should continue its discussions with municipal authorities and local interests

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[1] All monetary values are expressed in 1984 constant dollars.

TABLE 3 DIRECT PROVINCIAL MONETARY IMPACT AND NET BENEFIT
Millions of 1984 Dollars

	Shell	Board
Resource Utilization		
Capital Costs	295	295
Operating Costs	1496	1451
Net Benefits		
Provincial Corporate Tax	82	82
Provincial Royalties	311	311
Municipal Taxes	-	45
Profit Reinvestment	170	-
Federal Tax Requittal	30	-
Alberta Share of Profits	-	6
TOTAL NET BENEFIT	593	444
TOTAL DIRECT IMPACT	2384	2190

to ensure that the potential for adverse social impacts is clearly understood, and that the appropriate mitigative measures are undertaken. The Board views the prospect of increased local employment as a potentially positive local impact due to the significant level of unemployment currently experienced in the region. The Board notes, however, that Shell's employment estimates during the construction phase are based on the assumption that conventional field construction techniques would be employed. Recognizing that Shell is contemplating the use of modular construction methods, which would decrease the requirement for on-site construction workers, the Board views Shell's employment estimates as a maximum.

11 LOCAL EMPLOYMENT AND BUSINESS OPPORTUNITIES FOR NATIVES

Interventions submitted by the Council, the Whitefish Lake Indian Band, and Duncan's Band included a number of proposals to enhance opportunities for Native employment in PREP. In addressing this matter, the Board notes that it does not have the jurisdiction to prescribe measures ensuring the employment of special groups as conditions of Board approval. However, as the issues raised by the interveners are of public concern, they are outlined here for the information of the Lieutenant Governor in Council and other interested parties.

The Council stated that it supports Shell's hiring policy that intends to give first preference to qualified local residents seeking employment. However, the Council recommended that the boundaries of Shell's preference hiring region be extended to include the Whitefish Lake Indian Band and Duncan's Band, located 50 and 70 miles, respectively, from the plant site. Citing member band unemployment rates of 70 per cent, the Council argued that the boundaries should be defined in accordance with the employment needs of the local residents and their willingness to commute to the work site. In this regard and in response to a request from Shell, the Council submitted a proposal for implementing a rotational work force program involving two crews drawn from member bands that would work alternate shifts. The Council stated that it would be prepared to arrange transportation and basic training for participants in the program to ensure a stable and reliable work force. In addition, the Council encouraged Shell to undertake programs designed to assist local and Native-owned companies in identifying, tendering, and performing contract services. The Council noted that Shell is currently reviewing job qualifications for the project. Furthermore, in co-operation with Shell, the Council has undertaken to identify and catalogue the individual skills of persons expressing an interest in employment.

Shell indicated that its selection of a preference hiring region was based on its intent to offer employment to individuals living in communities that would be adversely affected by the project. In determining which communities should be included, Shell assessed the proximity of the construction camp and the anticipated disturbance from the increased traffic flows required for the shipment of construction materials. In Shell's view, the

Whitefish Lake Indian Band and Duncan's Band reside in areas that are not within a manageable commuting distance to the site, and would not be adversely affected during the construction period. For these reasons, Shell maintained that these bands should remain outside the preference hiring region. With respect to the Council's recommendations on implementing a rotational work force program, Shell indicated that virtually all construction work would be contracted, and it was not in a position to implement a rotational work force program. Notwithstanding the above, Shell indicated its on-going willingness to meet with the bands to discuss areas of mutual interest.

In considering these matters, the Board believes that affording opportunities to qualified Native people is desirable and in the public interest. The Board recognizes, however, that a sustained and dedicated effort on the part of all concerned groups is necessary to satisfy this objective. The Board notes that meaningful communication has taken place between Shell and the Indian bands and supports continued discussion and co-operation so that practical opportunities are identified and promoted by both parties.

12 DECISION

The Board is prepared to approve the expansion of PRISP to commercial operation of PREP. The Board will proceed to obtain an Order in Council authorizing the granting of the approval.

DATED at Calgary, Alberta, on 8 November 1984.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

PANCANADIAN PETROLEUM LIMITED APPLICATION FOR A WELL LICENCE

Decision D 84-27
Application 840639

BOARD DECISION

The Board concurs with the findings and recommendations of Mr. L. A. Bellows with respect to Application 840639 by PanCanadian Petroleum Limited for the reasons set out in his report.

The Board directs that Application 840639 be approved.

DATED at Calgary, Alberta, on 12 November 1984.

ENERGY RESOURCES CONSERVATION BOARD

GJDeSorcy

G. J. DeSorcy
Vice Chairman

VE Bohme

V. E. Bohme
Board Member

1 INTRODUCTION

1.1 The Application and Intervention

PanCanadian Petroleum Limited (PanCanadian) applied pursuant to Part 2 of the Oil and Gas Conservation Act for a well licence to drill a well in the Gleichen Field in legal subdivision 16 of section 33, township 23, range 21, west of the 4th meridian (Lsd 16). The purpose of the proposed well, PCP GLEICHEN 16-33-23-21 (the well), would be to obtain production from the Medicine Hat sand.

An intervention opposing the application was filed by Mr. Gordon Will (Mr. Will) on behalf of Will Farms Ltd. (Will Farms), the owner of the lands.

1.2 The Hearing

A public hearing of the application was held on 30 August 1984 at the offices of the Energy Resources Conservation Board (the Board) in Calgary, Alberta, before Board Member, L. A. Bellows, P.Eng. Prior to the presentation of evidence, counsel for Will Farms submitted that Mr. Will was unable to attend that day due to problems with harvesting and requested an adjournment.

PanCanadian submitted it did not feel the request was reasonable because sufficient notification of the hearing had been given to Will Farms.

After consideration of the arguments from the applicant and intervener by the Board member, the hearing was adjourned until 18 September 1984 at which time the PanCanadian application was considered.

1.3 Preliminary Matters

PanCanadian stated that the well was needed to produce its gas reserves and this position was not disputed. Further, PanCanadian and Will Farms agreed on the location of the well site in the northeast corner of Lsd 16.

2 ISSUES

PanCanadian applied to license the well at a location 40 metres (m) south of the north boundary and 40 m west of the east boundary of Lsd 16. The applicant had previously agreed with Will Farms to locate the well 40 m south of the north and 23 m west of the east boundary, but had been unable to obtain the consent of the County of Wheatland No. 16 (the County) to this location.

Evidence was presented that a county by-law prohibits the location of a well within 38.1 m of a road allowance, and that the by-law was passed pursuant to the provisions of the Planning Act. Will Farms argued that the by-law is of no effect because section 3(b) of the Planning Act provides that the Planning Act does not apply when a development is effected solely for the purpose of a well within the meaning of the Oil and Gas Conservation Act. PanCanadian agreed with this position.

PanCanadian argued that the Board had three alternatives with respect to the disposition of this application:

- grant the licence for the well location as applied for, or
- grant the licence with the condition that the location be 23 m west of the east boundary, or
- deny the application.

PanCanadian argued with respect to the second alternative that the Board has the power, given section 14 of the Oil and Gas Conservation Act, to alter the applied-for location of the well.

The Board believes that it does not have the authority to rule on whether the County's by-law is valid. The Board

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
PanCanadian Petroleum Limited (PanCanadian) D. Larson	A. Oxtoby, P.Eng. D. Worobec
Will Farms Ltd. (Will Farms) D. B. Reesor B. Machny	G. Will (Mr. Will)
Energy Resources Conservation Board staff H. R. Hansford N. F. Lord	

further believes that it cannot grant a licence for an alternative location which was not applied for, and for which notice had not been given to potentially affected persons who were not present at the hearing.

The only remaining issue, therefore, is whether the impact of the well on farming operations in the applied-for location is such that, in comparison to other potential locations, the Board should deny the application.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of PanCanadian

PanCanadian submitted that its preferred location for the well was that as applied for, 40 m from the northern boundary and 40 m from the eastern boundary of Lsd 16. This would accommodate most standard drilling rig configurations.

In order to move the well to a location 23 m from the eastern boundary, PanCanadian submitted that a specific type of rig is required to accommodate a reorientation of surface facilities during the drilling phase of operations. This would include reorientation of the rig crown, the sump, and flare pit from a standard rig and well-site layout. PanCanadian stated that a rig of this type is available but that it may or may not be available at any given time.

PanCanadian was of the opinion that this unique configuration would increase the hazard involved with the drilling operations and is from a safety aspect undesirable. PanCanadian submitted further that because increased piping would be involved with reorientating the rig layout, the risk of equipment failure would be increased. Further, PanCanadian took the position that the close proximity to the country road could present an increased visibility hazard to traffic.

PanCanadian submitted that it would cost an additional $10 000 or more to accommodate a 23 m setback from the east boundary of the lease.

PanCanadian summarized that it was reluctant to proceed in the placement of the wellhead 23 m from a road allowance because of the increased cost, safety hazards, equipment reorientation, and rig availability.

3.2 Views of Will Farms

Mr. Will had a number of concerns with respect to the impact of the proposed well, being primarily dislocation of farming operations, safety, and conservation of the land.

Mr. Will submitted that in planning a well site in conjunction with farming operations, two approaches were possible. The first is to position the well site far enough into a field so as to ensure farming on both sides of the well site; however, it was his experience that this arrangement became obsolete in a short period of time. The second is the position Will Farms adopts with other operations, which is to minimize the impact at the outset. This would entail determining what areas will be given over to the operation of a well, minimize these, and then intend on farming the adjoining areas.

Mr. Will submitted that as a wellhead is located further out into a field, the adverse effects increase exponentially. The problems that may arise are:

- Additional turning of farm equipment. This would be required to accommodate farming around the wellhead. Additional turns carry out into the field causing dislocation to crop pattern.
- Doubling up of chemical application.
- Accommodating the constraints associated with working around a well site as equipment size varies.
- Increased safety hazards as the number of passes by a well site with equipment increases.
- Erosion and vegetation control. Areas which are placed out of permanent crop production become susceptible to erosion or, depending on the form of vegetation control used, may be substantially more difficult to reclaim.

Mr. Will submitted that though Will Farms would prefer to have the well as close to the eastern boundary of the lease as possible, the 23 m setback distance was arrived at as a compromise which would best suit the needs of Will Farms and PanCanadian.

3.3 Views of the Board

The Board agrees with Mr. Will that the area to be used in the drilling and producing of a well located on farm land should be minimized. The Board must emphasize that the remaining adjoining lease areas may be farmed only with the agreement of the licensee. The minimum land required should, however, be determined in conjunction with "good oil field practice". Special conditions or requirements beyond such practice must be compared to the resulting reduction of impact on agricultural operations. In this case, the distance between the well location applied for and that proposed by Will Farms is 17 m. It appears that this alternative location will require some additional turning of farm machinery depending on the direction of operation, which would result in some extension of altered field patterns and slightly increased risk. In addition, a small amount of additional land, mostly 17 m of additional road, will have to be maintained and ultimately reclaimed. In order to achieve this reduction in impact, PanCanadian would find it necessary to contract a specific drilling rig, or type of drilling rig, and alter the rig equipment at a cost of about $10 000. The alternative could present some problems with safety because the equipment layout would not be conventional.

Considering the above, the Board does not believe that the impact on agricultural operations of the well as proposed by PanCanadian is unacceptable, nor does it believe that an alternative location as proposed by Will Farms is practical considering the modest reduction in impact.

4 RECOMMENDATION

It is recommended that Application 840639 by PanCanadian Petroleum Limited for a licence to drill the well, PCP GLEICHEN 16-33-23-21, be granted.

DATED at Calgary, Alberta, on 9 November 1984.

L A Bellows

L. A. Bellows, P.Eng.
Board Member

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A Report on an Application by Canterra Energy Ltd. to Drill a Critical Sour Well in the Sundre Area

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A Report on an Application by Canterra Energy Ltd. to Drill a Critical Sour Well in the Sundre Area

December 1984

ENERGY RESOURCES CONSERVATION BOARD
DECISION REPORT

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CONTENTS

Page

1 DECISION SUMMARY 1

2 APPLICATION 2

3 INTERVENTIONS 2

4 HEARING 2

5 PRELIMINARY MATTERS 5

6 BASIS FOR MAKING THE DECISION 5

7 PURPOSE OF THE WELL AND THE NECESSITY THAT IT BE LOCATED AS PROPOSED BY CANTERRA 6

8 MAXIMUM POTENTIAL H_2S RELEASE RATE 7

9 PRECAUTIONS TO BE TAKEN DURING DRILLING AND THE CHANCES OF A BLOWOUT – NON-CRITICAL WELL SECTION 9

10 PRECAUTIONS TO BE TAKEN DURING DRILLING AND THE CHANCES OF A BLOWOUT – CRITICAL SECTION 11

- 10.1 Geological Prognosis 11
- 10.2 Casing Design and its Impact on the Critical Section 11
- 10.3 Drilling Equipment 12
  - 10.3.1 Blowout Preventers and Associated Equipment 12
  - 10.3.2 Mud-Conditioning Equipment 13
  - 10.3.3 Drill Pipe 14
  - 10.3.4 Kick-Detection Equipment 14
  - 10.3.5 H_2S Trim Equipment 15
- 10.4 Safety Equipment 15
- 10.5 Supervisory and Other Personnel 16
- 10.6 Drilling and Kick-Control Procedures 16
- 10.7 Detailed Drilling Plans 18
- 10.8 Role of ERCB Field Staff if Well Licence is Issued 18
- 10.9 Chances of a Blowout at the Proposed Well 19

11 ACTIONS TO BE TAKEN IN CASE OF A BLOWOUT AND THE RESULTING IMPACTS 20

- 11.1 Actions to be Taken 20
- 11.2 Plans for Capping Well 25
- 11.3 Impacts of a Blowout 25
- 11.4 Summary Views 29

12 TEST PHASES AND LIKELIHOOD OF FURTHER DEVELOPMENT 29

- 12.1 Testing 29
- 12.2 Likelihood of Further Development 29

13 FINDINGS 30

14 DECISION 32

APPENDICES

Page

Appendix 1 Glossary of Terms 35

Appendix 2 Area Map, Figure 1 45

Appendix 3 Geological Cross-Section 47

Appendix 4 Resident Map, Figure 2 49

Appendix 5 Draft Interim Directive (Phase 2 – Lodgepole) 51

Appendix 6 Well Ignition Criteria 57

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY CANTERRA ENERGY LTD. TO DRILL A CRITICAL SOUR WELL IN THE SUNDRE AREA

Decision D 84-28
Application 830495

1 DECISION SUMMARY

This first section of the report provides concise comment on the application, public hearing, and decision of the Energy Resources Conservation Board (Board) for a proposed sour gas well in the Bergen area south of Sundre. This was a complex proceeding and the body of the report details the Board's consideration of the issues raised. This summary cannot convey the depth of consideration given to all the issues, and the interested reader is invited to review the summary of evidence and the "Views of the Board" respecting each of the issues and culminating in the findings and decision.

In August of 1984, the Board convened the first public hearing of a potentially high release rate critical sour well since the Lodgepole blowout inquiry Phase 2 report[1] (Lodgepole Phase 2 report) was issued.

The May 1983 application by Canterra Energy Ltd. (Canterra) proposed drilling a well in the Sundre area that could encounter high concentrations of hydrogen sulphide (H_2S), thus classifying the proposed well as a "critical well" as defined in the Draft Interim Directive attached as Appendix 5 of this report.

Earlier in the year, residents of the surrounding area had expressed great concern and asked for additional time to study and understand the proposal by Canterra. The public hearing originally scheduled for June was deferred until August to allow technical experts representing the Bergen Ratepayers Association (Bergen Group) and others to complete their review of the application.

Through the course of the hearing there was considerable discussion of the potential release rate of H_2S, drilling safety, public safety, and the ignition criteria for firing the well should there be an uncontrolled release of gas. The body of the report outlines the details of these topics, which the Board reviewed from the perspective that if there were no demonstrated need for the well, the matter would end right there and, even if the need were demonstrated, the safety of the public would remain paramount. Furthermore, even it if could be shown that an uncontrolled release of gas was unlikely, the Board would examine the consequences of an uncontrolled release to determine whether public safety could be maintained.

As set out in its findings in section 13 of the report, after reviewing all the evidence and taking into consideration the added precautions that must be taken as a result of the Lodgepole Phase 2 report, and the additional equipment and procedures as outlined by Canterra, the Board is satisfied that the probability of an uncontrolled release can be made acceptably low if the most up-to-date procedures and precautions are maintained. In this case, "acceptably low" means that the probability of an uncontrolled release is judged to be low enough to make it unlikely that residents of the area would have to endure an evacuation and other inconveniences. Notwithstanding that every effort would be made to avoid an uncontrolled release, the Board believes satisfactory measures can and must be in place to ensure public safety if a release should occur. Thus, ignition criteria and other safety measures would be essential and, as discussed in the report, the Board believes these measures could adequately protect the public.

Having concluded that Canterra has established a need for the well, and that public safety can be maintained, the Board is prepared to issue a well licence to the applicant, subject to conditions outlined in this report that are stringent and designed to ensure not only a low probability of an uncontrolled release, but also public safety in the event that a release does occur.

2 APPLICATION

Canterra applied pursuant to the Oil and Gas Conservation Act (the Act) for a licence to drill a well in legal subdivision 12 of section 12, township 32, range 6, west of the 5th meridian (the proposed 12-12 well). Canterra stated that the purpose of the well would be to evaluate and obtain production from the Leduc Formation. Canterra anticipated that if the target formation is penetrated, the reservoir could potentially contain sour natural gas with an H_2S content of 90 per cent. A potential H_2S release rate of 3.85 cubic metres per second (m^3/s) was estimated by the applicant which would result in a Level 3 facility as defined in Interim Directive ID 81-3[2]. No liquid hydrocarbons are anticipated.

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[1] Decision D 84-5, Lodgepole Blowout Inquiry – Phase 2. Sour Gas Well Blowouts In Alberta: Their Causes, and Actions Required to Minimize Their Future Occurrence.

The attached map (Appendix 2) shows the proposed well-site location relative to several nearby communities and other geographical landmarks.

The well was designated a critical sour well as defined in the Draft Interim Directive attached to the Lodgepole Phase 2 report. The Draft Interim Directive is included as Appendix 5.

Included in the application was information pertaining to geology, potential release rate determination, the proposed drilling program, post drilling operations, and a proposed emergency response plan. The proposed drilling program section included information on drilling time, casing and cementing details, blowout prevention (BOP) equipment, drilling fluids, and well-site personnel. It is important to note, however, that the submitted program did not contain all the details referred to in the Draft Interim Directive. Canterra took the position that if the requested well licence was issued it would submit more detailed information to satisfy Special Requirements 1 to 5 of the directive.

The application indicated that if a well licence was obtained and a successful well completed, the possibility existed that from 12 to 15 more wells could be required to produce reserves in the area. The drilling of these wells would likely lead to the construction of a field battery[3] facility and pipelines to transport the products to the Ram River gas plant. Canterra stated that applications to drill the wells and build the facilities, as well as an application to perform a production test on the 12-12 well, if licensed and successfully drilled, would have to be submitted to the Board and may be the subject of future hearings.

3 INTERVENTIONS

The Board received a number of interventions from community groups, individuals, and local municipalities in the area, many of which opposed the drilling of the well. Interveners questioned the need to drill a sour gas well at this time since considerable stockpiles of sulphur presently exist in the province. The interveners stated that the economic gains made by the applicant, and by the province as a whole through royalties, did not outweigh the value of the land and the contributions the farmers of the area made to the province through crops and livestock raising.

It was the general belief of the interveners that there was no previous experience, by the applicant or any other company, in drilling and eventually producing a well with 90 per cent H_2S content gas. Considering the untested technology to be used, the interveners classified the well as experimental, and it was their opinion that such a densely populated rural area was not the proper place to be proving the technology.

The qualifications of the on-site supervisors and the training procedures to be used with the rig crew were also areas of concern to the interveners, as was the BOP equipment to be used and the procedure for blowout practice drills.

A few interveners stated that drilling program information was incomplete. Previously drilled wells in the area indicated the possibility for lost circulation and overpressured zones. The drilling program, in the interveners opinion, should include written procedures for handling such situations.

A major area of concern for all interveners was the emergency alert and evacuation plan proposed by the applicant. They generally suggested that the release rate calculated by Canterra was too low and that there was a need for a much larger evacuation zone than Canterra proposed. A number expressed concerns about the lack of evacuation routes out of the area, the means of communication with residents in the event of an evacuation, the need for special provisions for people with known health problems, and the care of livestock during an evacuation.

Most interveners contended that the effects on health and agriculture due to a blowout are not fully understood, as studies are not available on the effects of H_2S or sulphur dioxide (SO_2) on livestock and humans, especially long-term effects of low-level releases.

The appropriateness of testing the well and the feasibility of pipelining the well effluent, considering its composition, were questioned by the interveners. Concern was expressed that if a successful well was drilled more would follow, and if production could not be transported by pipeline, then a gas plant would be built in the area causing a further impact.

4 HEARING

The Board issued a preliminary notice of hearing in late November 1983 stating its intention to hold a public hearing of the application sometime in April 1984. Notice of a hearing to be held on 4 June 1984 was issued on 2 April 1984.

Several applications for a hearing delay were received from interested parties and a pre-hearing meeting on

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[2] Interim Directive ID 81-3, Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments.

[3] The definition of this and other oil-field terms used in the report is given in Appendix 1, a Glossary of Terms.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Canterra Energy Ltd. (Canterra)	J. E. Martin, P.Eng.
F. M. Saville, Q.C.	W. H. Sawotin, P.Eng.
R. A. Neufeld	R. L. Thomas
C. P. MacDonald	R. Reid
	D. R. Lewis, P.Eng.
	J. K. Farries, P.Eng.[1]
	D. A. McCoy
	Dr. R. A. Crowther[1]
	M. B. Schroeder[1]
	Dr. D. M. Leahey[1]
	Dr. J. B. Hyne (A.S.R.C.)[1]
	D. P. Huffman
	D. A. McIntyre[1]
	J. Kingsbury, P.Eng.
	G. Brar, P.Eng.[1]
Bergen Ratepayers Association (Bergen Group)	S. Burton
S. R. Miller	M. Goodwin
	J. Grimstead
	C. Grimstead
	V. Milo, P.Eng.[2]
	J. R. Eickmaier, P.Eng.[2]
	N. E. Draper, P.Eng.[2]
	A. S. Murray, P.Eng.[2]
Inter-Varsity Christian Fellowship (Pioneer Lodge)	J. S. Fisher
J. S. Fisher	
Community of Fallen Timber (Fallen Timber Group)	B. L. Goodall, P.Eng.
B. L. Goodall, P.Eng.	
R. Bailey	
Town of Sundre	H. Doering
Mayor C. Vanderzwan	C. Currie
Mountain View Land Holders Group	
A. L. Dickson	
W. J. Waters	

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[1] Consultants appearing on behalf of Canterra.

[2] Consultants appearing on behalf of the Bergen Group.

TABLE 1 (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
City of Red Deer	C. Currie
Mayor R. J. McGhee	
C. Currie	
Amoco Canada Petroleum Co. Ltd.	
M. L. Pillman	
S. Burton[3]	
G. E. Cloakey[3]	G. E. Cloakey
B. Goodwin[3]	M. Goodwin
M. Goodwin[3]	
J. Grimstead[3]	J. Grimstead
C. Grimstead[3]	C. Grimstead
I. Halvorson[3]	I. Halvorson
M. Halvorson[3]	M. Halvorson
T. Worobetz	M. Worobetz
M. Worobetz[3]	
The Bauman Family[3]	Dr. J. A. Bauman
J. Haug[3]	
J. Orr[3]	
Dr. R. Huisman	
Mr. A. Newell	
Energy Resources Conservation Board staff	
M. Bruni	
G. Dunn, P.Eng.	
D. Price, P.Eng.	
W. Thorne, P.Eng.	
C. Milbury, P.Eng.	

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[3] Members of Bergen Ratepayers Association but also appeared on their own behalf.

25 May 1984 considered these requests. The Board deferred the hearing until 1 August 1984 to provide additional time for the interveners to prepare their submissions.

The public hearing of the application commenced on 1 August 1984 at Sundre, Alberta, before G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and L. A. Bellows, P.Eng., and continued through the days of 2, 3, 7, 8, 9, 10, and 11 August.

5 PRELIMINARY MATTERS

At the outset of the hearing, the Board dealt with several matters put forward by Dr. Bauman. He submitted that, for a number of reasons, the Board should dismiss the application or, failing that, postpone the hearing until any regulation changes resulting from the Lodgepole inquiry had been finalized.

Dr. Bauman argued that the notice of hearing referred to natural gas whereas the application contained a geological prognosis indicating that the H_2S component of the well effluent could be as high as 90 per cent. In the opinion of Dr. Bauman, the application was more representative of a liquid or gaseous sulphur extraction, and by his interpretations of the Act, this did not represent an energy resource and was therefore not within the jurisdiction of the ERCB.

In addition, Dr. Bauman argued that the application was incomplete because it failed to meet all of the requirements of the Draft Interim Directive attached to the Lodgepole Phase 2 report, in particular, section B, subsections 4, 5, and 6 of Attachment 1 to that document, referring to specific information to be submitted about the emergency planning zone.

Dr. Bauman contended that an apparent contact between the applicant and the Board staff during preparation of the application constituted a conflict of interest on the part of the Board. His view was that the Board had participated in the making and review of the application and therefore was not in a suitable position to decide it.

Mr. Cloakey expressed concern that the application made by Canterra lacked a site-specific emergency response plan and thus was incomplete. However, he preferred to deal with this during the hearing as opposed to having the hearing postponed to a later date.

In response, counsel for Canterra suggested that the Board dismiss the request of Dr. Bauman and continue with the hearing. The applicant argued that the definitions of "gas" and "raw gas" as outlined in the Act gave the Board jurisdiction to decide whether the type of well proposed should be drilled.

Canterra pointed out that the Draft Interim Directive referred to by Dr. Bauman was made public a few days after its submission was filed with the Board. It was Canterra's position that it was up to the Board staff to decide if the application was ready to go to a hearing.

The applicant submitted that contact between Board staff and the public, which includes Canterra, is a necessary process to fully understand what is required by the Board especially with respect to emergency planning.

After adjourning for about an hour to consider the arguments presented, the Board denied the requests of Dr. Bauman and the hearing proceeded. The Board stated that, in view of the definitions of "gas" and "raw gas" in the Act, it believed it had the jurisdiction to hear and decide on the Canterra application.

In regard to the Draft Interim Directive, the Board ruled that it had sufficient information before it to proceed with the hearing and that the purpose of the hearing was, at least in part, to test whether the information was complete and accurate. The Board stated that the applicant must satisfy it with respect to all statutory regulations and requirements before a well licence could be granted. It also confirmed that the Draft Interim Directive was in force and that Canterra must satisfy the Board on all aspects of that directive.

The Board also stated that it is appropriate for the staff to review applications, and as required, have contact with applicants, interveners, and other members of the public. Without this opportunity for communication, the entire process would be stifled or very inefficient due to misunderstanding of the meaning of directives, requirements for information in applications, hearing procedures, and other matters. The Board said that the process does not imply commitment regarding the approval of an application.

6 BASIS FOR MAKING THE DECISION

The applied-for well is clearly a critical well as defined in the Draft Interim Directive. Indeed, because the proposed well would be located in a fairly heavily populated rural area and the intended production would contain approximately 90 per cent H_2S, the Board believes a detailed assessment of the application is necessary before a licence could be contemplated.

The Board will first assess

- the purpose of the well and the necessity that it be located as proposed by Canterra.

There was much discussion at the hearing respecting the flow rate that could be expected from the proposed well and the resulting H_2S release rate should an accident occur. The Board believes this "maximum potential H_2S release rate" to be of underlying importance to public safety and all of the issues it would consider in assessing the application. For this reason it will next look at

- the maximum potential H_2S release rate for the proposed well.

Keeping in mind the estimated maximum release rate, the Board will then review the evidence and consider

- the precautions to be taken during the drilling of the well and the chances of a blowout occurring, and
- the actions to be taken in case of a blowout and impacts that could result.

Even though the application is for a well licence, the Board will next review

- the testing and production phases if a successful well is drilled andthe likelihood of further developments in the area.

The assessment of this final issue will be less detailed because subsequent applications would be required before such activities could proceed. This approach is consistent with the manner in which evidence was presented at the hearing.

Having reviewed the above listed issues, the Board will then consider all of them, giving appropriate weights to their relative importance, in making the decision as to whether a well licence will be issued and, if so, the conditions that should be attached to it.

7 PURPOSE OF THE WELL AND THE NECESSITY THAT IT BE LOCATED AS PROPOSED BY CANTERRA

7.1 Views of Canterra

The purpose and necessity of the proposed well were discussed at some length and in several contexts during the hearing. The well would be exploratory in nature with the company's main objective being to prove the presence of and evaluate the sour gas resources of the Leduc Member in the area. Other prospective zones would be tested for potential hydrocarbon recovery.

Canterra emphasized that it is in the business of exploring for and developing hydrocarbon and mineral resources. It contended that this well is a necessary part of that function. Canterra holds the mineral rights, and wishes to evaluate its holdings, and hopefully delineate its reserves by drilling the applied-for well. In addition, Canterra stated that it was necessary to drill the well to meet farm-in commitments.

Canterra also stated that the well would provide a high concentration sour gas source where it could test production methods. It proposed using catalyzed dimethyl disulphide as a solvent to reduce or prevent sulphur plugging in the well. Although it had not yet tested the solvent in any production conditions, it believed that the solvent would be substantially more efficient than anything used to date. Dr. Hyne stated that the solvent capability could be well over 200 weight per cent as compared with 30 weight per cent for carbon disulphide (which is currently in use).

It was Dr. Hyne's evidence that the use of catalyzed dimethyl disulphide puts the industry in a position to proceed with plans to produce high H_2S wells such as the one applied for. He said that testing of production methods at wells outside the Bentz Complex (Complex) may not be applicable to the proposed well. Mr. Martin, when asked about conducting tests at a well in 12-21-33-6 W5M (the Bearberry well), dismissed the possibility on the grounds that it was not owned by Canterra. He later stated that, even if Canterra owned the Bearberry well, it would still be the company's preference to go directly to the proposed location to establish reserves.

Canterra also addressed the issue of necessity from the point of view of product markets, and stated its prime interest in this area was sulphur. The company stated that it is one of the largest sulphur producers in Canada and "Through Cansulex . . . . Canterra accounts for 8 to 10 per cent of the world sulphur trade". Approximately 90 per cent of its production is exported and the majority used for the production of fertilizer. Mr. Martin and Dr. Hyne both commented on the long-term outlook for sulphur marketing and indicated that the demand would meet or exceed supply on a worldwide basis within this decade.

Canterra stated that its ability to satisfy demand would be reduced beyond 1988 as more accessible inventories are depleted. In order to maintain its sales at current levels, new reserves, such as those in the Complex, will be needed.

Mr. Martin also commented on the overall economic benefit to all Albertans, and that the sulphur industry contributes approximately $250 per person per year to our standard of living.

Canterra was asked a number of questions on the possibility of producing this reserve without drilling at the proposed location. In response, it stated that there was little alternative based on its interpretations of the geological information. Canterra said that a directional well may be a possibility, but this would not significantly affect the surface location and might adversely affect drilling safety by complicating the drilling program.

7.2 Views of Interveners

A number of local interveners questioned the purpose and necessity of the proposed well. In particular, some alluded to the inexperience of industry not only in drilling but also producing wells containing 90 per cent H_2S. Mr. Cloakey, in his closing remarks, indicated that a number of technical matters "were not fully understood" nor "proven". Although these interveners related this matter more to safety than purpose or necessity, citing Canterra's lack of experience in the production or testing of such a well, there appeared to be a view that the need for the well was also questionable.

Some interveners suggested the possibility of testing the Bearberry well instead of drilling and testing at the proposed location. While the interveners seemed to argue that position mainly in a reservoir evaluation context, it was also implied that the production testing using the new solvent should be done elsewhere.

Several interveners questioned the need for sulphur production. While they did not present evidence to contest Canterra's prediction of world sulphur requirements, there was some suggestion that current sulphur inventories and reserves were adequate to meet foreseeable requirements.

Mrs. Grimstead expressed a view that the rights of industry were being given a high priority compared to environmental costs, which would be borne by the public. She made these comments on behalf of the Bergen Group as well as herself. The interveners generally acknowledged the legal rights of industry to explore for and win its minerals, however, the theme of their concerns was that this right could impose adverse effects on at least particular sectors of the public.

Although there were some questions to Canterra regarding the possibility of drilling this well from another location, there was no evidence to suggest that this particular reserve could be evaluated and tested from such a location.

7.3 Views of Board

The Board has carefully considered the evidence respecting the purpose and necessity of the proposed 12-12 well. It notes that Canterra has a lease and a right to explore it, subject to satisfying regulatory and other Alberta laws. The additional reserves of natural gas and particularly sulphur, and the technology which Canterra hopes to prove, would represent significant benefits to Alberta and Canada. Although the Board recognizes these factors as important, it agrees with many of the interveners that such factors must not override producing the resource in a manner which is acceptable in terms of impact on the public, particularly public safety. As a consequence, even though it believes there is an adequate need for the proposed well, the Board must satisfy itself on the issues of public safety and other impacts before it would grant the requested well licence.

The Board considered requiring the applicant to evaluate its new production technology and solvent at some other location, more remote from farms and centres of population. Although it is of the view that conducting the test at such a location would be desirable, it notes Canterra's evidence that the technology would have to be tested in the specific reservoir to be certain of its success and to design proper production facilities. The Board also recognizes that testing the technology at a remote location would not address a primary purpose of the proposed well, that is, to explore and prove-up possible reserves. For these reasons, the Board is not prepared to deny the application to drill the proposed 12-12 well solely because the technology could be tested elsewhere. On the other hand, the Board is aware that Canterra has more remote leases elsewhere in the province which involve high H_2S gas. It understands that Canterra plans to test its technology at a well in such a setting in the near future. If the testing is carried out and is unsuccessful, thus suggesting that the technology has little chance of working, one of the major reasons for drilling the proposed 12-12 well would be significantly changed. With this in mind, if the Board finds that the 12-12 well can be safely drilled and is prepared to issue a licence, it would condition the licence so that commencement of drilling would not be allowed if tests in the province have raised significant doubts as to whether the proposed technology is likely to be successful.

With respect to the specific proposed location, the Board heard no evidence suggesting that there might be a better local surface location which would accomplish the purposes of the 12-12 well.

8 MAXIMUM POTENTIAL H_2S RELEASE RATE

8.1 Views of Canterra

Canterra estimated an H_2S release rate of 3.85 m^3/s which reflects a flow rate of 370 thousand cubic metres per day (10^3 m^3/d) (13.1 MMCFD) and a 90 per cent H_2S content.

Canterra used two methods in attempting to estimate the H_2S release rate from the proposed well. The first was to determine the most representative pool in the immediate area, and the second was to look at other Leduc pools in the general area and compare them to the most representative pool. It also considered sulphur deposition and its impact on expected flow rates.

Canterra stated that the proposed well is postulated to be part of the Complex, so wells in the Complex most closely approximate what is to be expected. The Complex well having the most available information is the Bearberry well drilled by Shell. Canterra therefore based its estimate on the 1969 absolute open flow potential (AOFP) test at that well.

Canterra emphasized that the quality of the test was somewhat questionable as essential pieces of data, such as field notes, surface pressure measurements, and volume of injection fluid, had not been recorded. However, from the test data, Canterra calculated a sandface AOFP of 760 x 10^3 m^3/d (27 MMCFD) and, assuming single-phase gas flow up the tubing, a wellhead AOFP of 563 x 10^3 m^3/d (20 MMCFD). This flow rate would result in a higher H_2S release rate than the submitted 3.85 m^3/s but Canterra contended that the assumption of single-phase gas flow made the estimate highly optimistic. It suggested that the actual wellhead AOFP would probably not exceed 155 x 10^3 m^3/d (5.5 MMCFD) if information on the amount of condensate being circulated, the amount of sulphur deposition, and a two-phase flow diagram had been available from the Bearberry test.

Canterra performed statistical analysis of wells in other Leduc fields in the immediate area. The study included the Bearberry well and wells from Ricinus and Harmattan-Elkton pools. A log-probability plot of 10 AOFPs indicated a 50 per cent probability of a flow rate of at least 370 x 10^3 m^3/d (13.2 MMCFD) which corresponds to an H_2S release rate of 3.85 m^3/s. Canterra stated that this supported its first estimate of a release rate using data from the Complex.

Canterra stated that West Ricinus wells were not included as they were not representative of the Bentz structure. However, when questioned about the geological differences between the pools, Canterra agreed that the differences between West Ricinus and the Complex were the same as between Ricinus and the Complex. However, it emphasized that there were differences in the reservoir fluids which would affect the capability of the wells.

Canterra also presented evidence respecting sulphur deposition to support its estimated H_2S release rate. It contended that the reservoir fluid in the Bearberry well is a supercritical gas because the compressibility and viscosity of the fluid were those of gas and not a liquid as was suggested by the Bergen Group. It also said that there is adequate evidence of sulphur plugging in the Bearberry well. The reservoir characteristics, porosity, and permeability are indicative of a much more prolific reservoir than the production tests showed. Sulphur deposition had significantly reduced the pore structure in the reservoir around the bottom hole and the test would not have been successful if solvent had not been circulated into the well. Canterra noted that the very rapid pressure build-up following the production test was further evidence of sulphur plugging.

Canterra submitted that, when a sour gas fluid is saturated or nearly saturated with sulphur, the amount of sulphur deposition depends on the pressure drop along the flow path from the reservoir to the wellhead. A larger pressure drop, such as would occur under open flow or uncontrolled conditions, would immediately decrease the sulphur carrying ability of the fluid. The minimum impact would be the precipitation of sulphur in the pore structure around the bottom of the hole and for some distance back into the reservoir. It stated that both field and laboratory experimental data on fluids containing a much lower percentage of H_2S than the 90 per cent expected in the subject well supported the concept that the faster the fluids flow the greater the sulphur deposition. Canterra concluded, therefore, that under blowout conditions the extent of sulphur deposition would be far greater than under normal operating conditions, and the flow rate would thus be rapidly reduced.

Canterra acknowledged that, under very high flow rates, it would be possible for the fluid to carry some of the precipitated sulphur from the reservoir up the tubing to the wellhead. Canterra said, however, that the scouring effect in the formation would probably not remove all the sulphur.

8.2 Views of Interveners

The Bergen Group presented several different approaches for estimating the H_2S release rate, four of which used data from the Bearberry well. The first estimate used the semi-steady state flow equation and conservative reservoir and fluid parameters to calculate a flow of 6070 x 10^3 m^3/d (215 MMCFD) assuming no "skin damage" and a permeability of 15 millidarcies (md). The Bergen Group acknowledged that initially there could be skin damage but stated that it would clean up after a brief flow period.

The second approach dealt with the specific productivity index. The Bergen Group submitted that the productivity index increased from 78 to 323 cubic feet per day per pounds per square inch (psi) drawdown during the Bearberry well test, which indicated the well was cleaning up. It assumed a drawdown of 2500 pounds per square inch absolute (psia) and used the productivity index of 323 cubic feet per day per psi to calculate a flow rate of 6600 x 10^3 m^3/d (234 MMCFD).

The Bergen Group also interpreted the Bearberry test and calculated an AOFP of 9160 x 10^3 m^3/d (325 MMCFD) using an "n" value of 1.0 which it stated should be used because the reservoir fluid was a liquid and would act as a liquid at reservoir conditions.

The Bergen Group submitted that the product of viscosity times the volume factor from the pressure volume temperature (PVT) data on the Bearberry well was relatively constant from the initial reservoir pressure of 5345 psia (36 855 kilopascals (kPa)) down to the bubble point. It then concluded that the fluid in the well would act as a liquid for pressures above the bubble point and that the rate-drawdown relationship would be linear, resulting in an even higher AOFP of 12 680 x 10^3 m^3/d (450 MMCFD).

From the four methods outlined above, if one assumes a 75 per cent value for the wellhead-sandface flow relationship and a 90 per cent H_2S content, the H_2S release rates would range from 47 to 99 m^3/s. The Bergen Group therefore concluded that the Bearberry well is completed in an extremely prolific reservoir.

The Bergen Group also performed a statistical analysis, consisting of individual and combined flow rate probability plots for the Harmattan-Elkton, West Ricinus, and Strachan Leduc pools. It noted that the combined probability plot resulted in a straight line, which is indicative of the data points being from the same population. The Bergen Group maintained that in this statistical analysis, a 10 per cent level of probability should be used as a conservative approach to protect the public. The Bergen analysis indicated a 10 per cent chance of the H_2S release rate being greater than or equal to 47.9, 98.9, and 100.9 m^3/s for the Harmattan-Elkton, West Ricinus, and Strachan pools, respectively. The combined plot results in an estimated release rate of 93.6 m^3/s.

The Bergen Group pointed to Canterra's own statement that "Canterra does not know the H_2S content in this well until they get a sample and that where sulphur will precipitate depends on how close the sulphur content approaches sulphur saturation and flowing temperature and pressure." It thus concluded that the influence of sulphur deposition on the flow rate would be unpredictable and should not be relied upon to significantly affect the flow rate from the proposed well.

8.3 Views of Board

The Board believes that in some instances a statistical analysis of AOFPs in other fields in the area of a proposed well would be a reasonable approach in determining the expected H_2S release rate of the well. However, in this case, the Board is of the opinion that because the proposed well is expected to be in the same complex as the Bearberry well, that well would likely be the most representative and a statistical approach would, in all likelihood, diverge from, rather than converge to, the best release rate estimate.

While the Bearberry well is of the most significance in estimating the H_2S release rate, the Board acknowledges that the actual test is of questionable quality. Its interpretation of the test indicates that the sandface AOFP could be as low as 760 x 10^3 m^3/d (27 MMCFD) as was calculated by Canterra. It does not believe the upper limit would be as high as suggested by some of the calculations submitted by the Bergen Group, but accepts that it could be as much as 1970 m^3/d (70 MMCFD). The latter estimate ignores possible effects of multiphase flow upon the calculated deliverability.

The Board believes that for wells such as that proposed, in the event of an uncontrolled flow, sulphur deposition would probably reduce the flow of fluid from the wellbore. The extent of this reduction, and whether or not the well would plug off completely is, at this point in time, not known. The Board notes that during normal producing operations, sulphur deposition causes restriction of flow in many sour gas wells throughout the province. However, to extrapolate this reduction of flow under producing conditions to a complete or even partial plugging off of flow during a blowout would not, in the Board's judgement, be prudent when estimating a release rate for purposes of protecting the public.

Using the conservative approach of neglecting the possible effects of sulphur deposition and multiphase flow, and assuming the wellhead deliverability to be 75 per cent of the sandface AOFP and a 90 per cent H_2S content, results in an H_2S release rate ranging from 6 to 15 m^3/s.

The Board does not necessarily expect that if the proposed well was drilled and a blowout occurred, the H_2S release rate would be as high as 6 to 15 m^3/s but believes it appropriate to consider that range for emergency planning purposes. Should the well be licensed and an ignition requirement be included as a condition of the licence, the latter would reduce the significance of estimates of the H_2S release rate.

9 PRECAUTIONS TO BE TAKEN DURING DRILLING AND THE CHANCES OF A BLOWOUT — NON-CRITICAL WELL SECTION

This section of the report deals with drilling the proposed well to a depth of approximately 3775 metres (m), some 110 m above the Leduc Formation in which sour gas may be expected.

9.1 Views of Canterra

Canterra's main objective was to evaluate the Leduc[4] Formation at 3887 m. It also identified a number of secondary objectives from the Cretaceous at approximately 1450 m through to the Beaverhill Lake at approximately 4140 m, the latter being below the primary objective of the Leduc Formation. The company would set 600 m of surface casing and then drill the "intermediate hole" to 3775 m, just above the Nisku and above the Leduc. This section of the hole would then be cased and cemented full length. The company acknowledged some possibility that the Rock Creek and Banff formations could have abnormally high pressures. It was also questioned about the Beaverhill Lake, but expected very low porosity and no abnormal pressure.

The company's general plan is to drill the intermediate hole using a diesel oil based invert emulsion mud system. The mud density would be increased to 1320 kilograms per cubic metre (kg/m^3) at a depth of 3025 m to ensure sufficient bottom-hole hydrostatic pressure is maintained through the Rock Creek (3172 m) and Banff (3322 m) formations. This would minimize the chances of any influx from these formations. Through the Cretaceous sequence (to 3025 m), the mud density would be maintained at a lower level as there was no evidence of abnormally pressured strata.

While Canterra accepted there had been some drilling difficulties with previous wells in the area, it generally took exception to the premise that this area presented special difficulties. It emphasized that the drilling program, as outlined, should effectively handle the predicted pressures as well as any other problems that may occur.

The company stated that lost circulation or underground blowouts, should either occur, would be handled by the use of high density mud, barite plugs, or by the use of cement. The applicant said that the chances of an underground blowout would be extremely low since all uphole formations would be cased and cemented prior to drilling through the Nisku and Leduc formations.

As indicated above, intermediate casing would be run to a depth of 3775 m and cemented full length with full strength cement from 3775 to 2200 m and filler cement above that. Canterra stated that offset well data indicated that the formation strengths were sufficient to withstand the full length cement job as proposed. The cement would not have an appreciably higher density than the mud proposed for the intermediate hole.

The company indicated that the intermediate casing was designed to meet current regulations and will be monitored for wear by intermittent pressure testing and caliper logs. If the intermediate casing is damaged during subsequent drilling operations, the company would repair the damage by the use of a casing patch or a tie-back casing string.

The applicant did not specifically state in its application or during the hearing how it would establish formation breakdown pressures in the intermediate hole, but did indicate that offset well data would be used to ensure dequate casing design and identify any overpressured zones.

9.2 Views of Interveners

The Bergen Group, through questioning, expressed concern for the possibility of encountering overpressured zones, as indicated by offset well data. It suggested that Canterra had not outlined a procedure that would be used to drill through the transition zones leading to and through the actual overpressured zone.

Mr. Murray expressed concerns about lost circulation and underground blowouts, but was not specific as to where the problems may arise. He also stated that Canterra should have a method outlined for testing the integrity of open formations to allow the drilling personnel to establish maximum allowable shut-in pressures. If this maximum shut-in pressure was not established, it is possible that if a high pressure kick from a lower zone entered the wellbore and the well was shut in, a weaker zone higher in the hole could be charged up to the higher pressure. This high pressure zone could cause a blowout in future drilling operations if such an underground blowout went undetected.

Mr. Murray also said that the procedures to be used in the placing and cementing of the casing string would be important in maintaining well control should a kick situation be encountered and suggested that the company should submit written procedures to outline pressure testing of the casing during drilling operations.

In addition, the Bergen Group expressed a number of other concerns which relate to the non-critical section of the well but, more importantly, to the critical section. These items are covered in the next section of this report.

9.3 Views of Board

The Board generally concurs with the outlined drilling procedures up to the point of setting intermediate casing. However, if it issues a licence, it would require the company in its detailed drilling plan to satisfy the Board with respect to:

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[4] Appendix 3 is a typical cross-section of geological formations in the region.

- the establishment of formation breakdown pressures in the intermediate hole, and
- casing inspection methods and testing frequency.

The Board notes that the mud density would be increased to 1320 kg/m^3 for certain zones and believes this weight to be sufficient to safely drill the zones, but would review the matter further when the final drilling program is submitted.

Although the Bergen Group's expert witnesses expressed concern about overpressured zones, possible lost circulation, or an underground blowout in the intermediate hole, the Board notes that no critical sour zones are expected to be penetrated. It concludes that there is nothing particularly unique about the intermediate hole, and that neither the chances nor the consequences of a blowout from the intermediate hole would be serious. If the well is drilled, the Board believes the primary objective with respect to the non-critical section would be to ensure proper design, running, and cementing of the intermediate casing in order that the well may be controlled should problems occur after entering the critical zone.

10 PRECAUTIONS TO BE TAKEN DURING DRILLING AND THE CHANCES OF A BLOWOUT — CRITICAL SECTION

This section of the report deals with the drilling of the proposed well through the Nisku and Leduc formations after the intermediate casing had been set. Due to the potential high H_2S gas and the resulting seriousness of the situation if problems occur, the Board is focusing particular attention on this "critical section" of the proposed well.

It should be noted in this and subsequent sections of the report that although the interveners opposed approval of the application to drill the well, they presented evidence as to conditions which should be imposed if the well is drilled.

10.1 Geological Prognosis

10.1.1 Views of Canterra

Canterra stated that the pressure gradients of the Nisku and Leduc formations as indicated by the offset wells are lower than a water gradient, which would indicate that neither of the zones are overpressured. The applicant said that the Nisku Formation in the area is non-productive and stated that none of the offset wells had experienced any lost circulation problems.

Canterra contended that the submitted drilling program sufficiently covered all possible problem areas indicated by the geological prognosis based on offset wells.

10.1.2 Views of Interveners

In general, the interveners did not disagree with the geology as outlined by the applicant, although several items of evidence were submitted by the Bergen Group which suggested problems occurred during the drilling of several other wells in the area.

Concern was expressed by Mr. Murray that if the Nisku proved to be productive, it could be a lost circulation zone. He also said the possibility exists that the Leduc could be an abnormally high pressured zone.

10.1.3 Views of Board

A review of the daily drilling reports submitted by the Bergen Group reveals that, with the exception of two events connected with drill-stem tests at the 11-35-33-7 W5M well, all other problem events related to the non-critical zones of the proposed well, zones which will be cased-off when drilling in the critical Leduc and Nisku formations. These non-critical well section matters were dealt with in section 9 of the report. The two drill-stem test problems appeared to relate to sulphur plugging of the drill pipe and were not the result of unusual pressures or lost circulation in the Nisku or Leduc zones.

It is the Board's view that the Nisku and Leduc are likely underpressured zones as indicated by the offset well information. The semi-dispersed gel system proposed for the drilling of these sections should be adequate to ensure good well control. Procedures for controlling lost circulation will be reviewed in greater detail when the final program is submitted.

As a consequence of its review of the geological prognosis, the Board would not expect that serious problems would be encountered while drilling the Nisku and Leduc formations. Nevertheless, there is always uncertainty as to what will be found, and caution is always necessary.

10.2 Casing Design and Its Impact on the Critical Section

10.2.1 Views of Canterra

The critical section of the well would be drilled through the Nisku, Leduc, and Beaverhill Lake formations. The program calls for drilling through the Nisku and coring the Leduc Formation. If the Leduc proved successful, the well would be cased and then the Beaverhill Lake would be drilled. If the Leduc was not successful, drilling would continue to a projected total depth of 4287 m, below the Beaverhill Lake, and then casing would be set to total depth.

Canterra, in response to questioning by the interveners, indicated that intermediate casing wear was to be monitored by running caliper logs and by pressure testing the casing while drilling the main hole. If either test indicated excessive casing wear, remedial action would be taken depending on the situation, and the applicant would obtain Board approval for such action. It was Canterra's view that the pressure rating of 61 megapascals (MPa) (burst rating) for the proposed casing was adequate. If higher than expected pressures were encountered, an additional casing string would be placed in the hole to withstand such pressures and isolate the outer casing.

The applicant stated that cathodic protection would be used to control external corrosion on the completed well. Additionally, annular spaces between tubulars would be filled with inhibited fluid to help prevent internal corrosion. Canterra also indicated that it had significant experience in the area of corrosion control and was confident that its corrosion program was adequate.

10.2.2 Views of Interveners

The Bergen Group expressed concern that the intermediate casing would be subjected to extensive wear as a result of drilling the main hole. Concern was also expressed that the pressure rating of this string may not be sufficiently high to withstand the pressures which might exist in one of the secondary objectives, such as the Beaverhill Lake.

Corrosion, in the view of the interveners, should be a major concern when considering the well design, not only the internal corrosion of the tubulars but also the external corrosion of the casing strings.

10.2.3 Views of Board

Generally, the Board is satisfied with the casing and cementing details, and considers it particularly important that if the Leduc proves productive, it be cased off before drilling deeper. The question of casing wear and the need to deal with it in the detailed drilling program has been dealt with under section 9.

The Board is satisfied with the corrosion control measures as outlined by the applicant. It is aware that the measures proposed by Canterra are proven methods used extensively in other sour gas operations.

10.3 Drilling Equipment

In response to questioning, Canterra identified the equipment it was proposing to use for the applied-for well. Although the company declined to fully describe specific equipment because a drilling contractor had not yet been selected, it was specific on most of its requirements. While there was considerable questioning about many items, the discussion can be divided into that dealing with five major categories of equipment:

- Blowout preventers and associated equipment
- Mud-conditioning equipment
- Drill pipe
- Kick-detection equipment
- H_2S trim equipment

10.3.1 Blowout Preventers and Associated Equipment

10.3.1.1 Views of Canterra

Canterra stated that it would be using a Class V[5] pressure rated BOP stack and manifold system with manifold arrangement as specified for Class VI. The stack would be modified by adding a spacer spool and a second set of pipe rams. This was done to eliminate the necessity of relying on the annular preventer to circulate a shut-in well. The stack and manifold specified would have a pressure rating of 35 000 kPa and the company indicated that it would be pressure tested in accordance with applicable requirements of the ERCB regulations. Canterra said it had decided to include a set of shear rams on the stack, and it would be located immediately below the blind ram on the Class VI configuration.

Canterra stated that the pressure testing and inspections of the BOP equipment would meet or exceed all Board regulations. Pressure tests would be performed on this equipment at various times including before drilling out of surface casing, prior to weighting up the mud system at a depth of 3025 m, before drilling out of intermediate casing and before entering the Leduc Formation. Each of these tests would involve a low pressure test and a high pressure test. Surface casing would be pressure tested to 12 600 kPa and the intermediate casing would be tested to a pressure of 23 700 kPa.

In response to the Bergen Group's questions respecting selection of a Class V BOP stack with a pressure rating of 35 000 kPa, Canterra stated that the pressure rating was suitable notwithstanding bottom-hole pressures in the Bearberry well may exceed this rating.

Canterra indicated that the choke manifold would be located away from the rig substructure approximately 20 to 25 m, and that there would be dual flare lines, one running to each side of the drilling site. Canterra stated that it had no preference in the type of pressure sensors used (piston or diaphragm), however, it agreed that thorough maintenance of these items was important.

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[5] Classes as described in Schedule 8, Oil and Gas Conservation Regulations.

Canterra said that there would be two BOP control panels, one near the driller's station and one at a "remote" location (at the accumulator unit). It expected that the controls would be electric but this would not be known until the rig was selected.

10.3.1.2 Views of Interveners

As well as addressing a number of questions to Canterra about the BOP equipment, the Bergen Group raised doubts through direct evidence respecting Canterra's plans. Mr. Murray questioned Canterra's ability to strip into the hole using the BOP stack as proposed. Mr. Sawotin, Canterra's drilling specialist, said that this operation would be done by alternately opening and closing the annular preventer and one of the pipe rams, thus allowing the tool joints to pass through the BOP stack while keeping the well closed in. Mr. Murray maintained that the annular preventer should be used only as a last resort and not unless "you really have to".

Mr. Murray also questioned Canterra's use of the cross below the lower pipe ram to bleed off any well pressure because if it were to be washed out (fail) there would be nothing left below the lower pipe rams to control the well.

Although the Bergen Group did not present an opinion about the pressure rating of the BOP stack and manifold system, it implied through questioning that the 35 000 kPa rating would be insufficient for this well, citing the somewhat higher bottom-hole pressure at the Bearberry well in the Leduc Formation.

10.3.1.3 Views of Board

The Board has considered the concerns expressed in connection with BOP equipment specified for use by Canterra, and although they are matters of interest, most of them are covered by appropriate design standards and regulations. The Board believes it appropriate, however, to comment on the major items addressed at the hearing.

The Board is satisfied that the equipment as proposed would have the capability to control the applied-for well if the equipment is operated and maintained in a workmanlike fashion. The shut-in pressure of approximately 18 700 kPa at the Bearberry well is believed to be representative of what can be expected at the proposed well and the Board is satisfied with the pressure rating of the proposed BOP equipment. The addition of a shear ram to the BOP stack would provide added safety features.

The Board finds the BOP stack arrangement and control system as proposed by Canterra to be acceptable, as well as its procedures to strip into the hole if necessary. The Board also concurs with Canterra's decision to use dual flare pits.

The pressure testing and inspections of the BOP equipment, and the blowout prevention drills, as outlined by the applicant are generally satisfactory. Such procedures are extremely important, however, and if a well licence is issued, they must be detailed in the final drilling program and further reviewed at that time.

10.3.2 Mud-Conditioning Equipment

10.3.2.1 Views of Canterra

Canterra would use the typical mud system for a well of the depth proposed, but additionally would use two so-called "poorboy" atmospheric pressure mud gas separators as the primary means of removing gas from the mud. It would also use a vacuum degasser to remove smaller quantities of entrained gas from the fluid. The second poorboy degasser would be used as a back-up to the first and would be remote from the rig.

The applicant planned to use a jet mixer for weighting up mud and stated that this would provide the best solution to quick weight-up requirements. It was Canterra's opinion that a standby mud system was not necessary as the drilling fluids would be maintained with sufficient yield point to ensure that the fluids could be weighted up as required.

10.3.2.2 Views of Interveners

None of the interveners presented detailed evidence respecting this matter, although Mr. Murray did question Canterra's ability to weight up severely gas-cut mud. He also suggested that a standby mud system would be more appropriate than the jet mixer proposed by the applicant. He said it was necessary to have the mud previously mixed to ensure that the fluid had a sufficient yield point to suspend the barite being added.

10.3.2.3 Views of Board

The Board has reviewed the statements of Canterra together with the information filed and believes if a licence is issued, the company should address more fully the methods of mud conditioning in its detailed drilling program. The plan should include a schematic of the mud circulating and conditioning systems, including the location and operation of isolating valves and redundant equipment. It should also provide for a volume of mud at surface, within the active mud system, in the order of 150 per cent of the hole volume at the time of drilling out the intermediate casing and throughout operations in the critical zone. It also should fully address the mechanics of monitoring the mud system, dealing with gas-cut mud, avoiding "clobbered" mud, and of weighting up mud.

The Board believes there is merit in having available an extra supply of premixed mud as well as the proposed high speed mixing equipment for the critical section of the well. It recognizes Canterra's position that reliance on a jet mixer would provide greater flexibility, but nevertheless is concerned at the time it may take to mix additional volumes if needed. For these reasons, the Board believes it would be appropriate to have the previously indicated excess volumes of mud, some 150 per cent of hole volume as compared to something less than 100 per cent as is more typically the case. The Board would also require that the jet mixer along with adequate accessible ingredients be available on site.

10.3.3 Drill Pipe

10.3.3.1 Views of Canterra

Canterra stated that it planned to use Grade E drill pipe for this particular well. For an overpull of 30 000 decanewtons, and omitting buoyancy effects, Canterra estimated a safety factor of 20 per cent on tensile strength. In addition to meeting the API[6] and NACE[7] standards respecting drill pipe, Canterra said that it would be carrying out ultrasonic inspection on the drill pipe and magnetic particle inspection of the tool joints. Conformance to NACE standards would be evaluated on the basis of hardness testing.

Canterra said it has metallurgical experts within the company who would supervise third-party inspection of the drill pipe prior to the well being drilled.

10.3.3.2 Views of Interveners

Although none of the interveners suggested that the use of Grade E drill pipe was unsatisfactory for the application proposed. Mr. Murray, on behalf of the Bergen Group, commented on the use of outside consultants and inspectors, particularly with regard to drill pipe inspection. He stated that inspection of the drill string should occur before spudding the well, before drilling out the intermediate casing, and after any sour gas invasion into the wellbore. The inspections should be done by a well-qualified inspection company and supervised by the applicant. Mr. Murray emphasized that a third party should not be totally relied upon to give accurate unbiased opinions and suggested that the company must have the expertise in house.

10.3.3.3 Views of Board

The Board concludes that with proper procedures the Grade E drill pipe proposed would be adequate for the well. The Board acknowledges the statements made by Mr. Murray regarding inconsistent inspection results, and agrees that the applicant must accept the responsibility for the pipe being properly inspected, even though the inspection would be by third-party experts.

Additionally, the Board believes that the drill pipe must be fully inspected prior to, and protected and maintained during, the drilling operation. If it issues a licence, the Board would require Canterra to specifically detail in its drilling program all matters in connection with the drill-string inspection, protection, and maintenance. The company should consider and show in detail its proposed methods of corrosion inhibition, H_2S scavenging, and maintenance inspections after the string has been contacted by H_2S.

10.3.4 Kick-Detection Equipment

10.3.4.1 Views of Canterra

Canterra stated that it would be using an electrically operated pit totalizer with probes in each active tank. In addition, the company would use a flow totalizer and a trip tank. The company also indicated that there would be continuous display readouts of tank levels and fluid flow information near the driller's station. Mr. Farries indicated that although the alarms may be set to detect very small pit gains, it would be realistically difficult to detect a pit gain of less than one cubic metre.

10.3.4.2 Views of Interveners

Mr. Murray, representing the Bergen Group, expressed concerns with the proposed kick-detection equipment. He indicated a concern with the ability of pit level indicators to give accurate results if the drilling fluids become "clobbered".

10.3.4.3 Views of Board

The Board generally agrees with the use of the kick-detection equipment proposed by Canterra but believes that a complete description of the equipment and its capabilities is necessary to fully evaluate its suitability. If the requested licence is issued, the detailed drilling plan should indicate the location, function, and application of each piece of equipment in the system. It should also address the matter of kick detection under adverse mud conditions (eg, gas-cut mud or "clobbered" mud).

The Board believes that the proper use of kick-detection equipment, and indeed essentially all drilling equipment, is equally important as the equipment itself in avoiding a blowout. For this reason, the detailed drilling program would also have to satisfy the Board that the crew will be properly trained respecting the use of kick-detection equipment and that particular care will be taken in this regard.

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[6] American Petroleum Institute.

[7] National Association of Corrosion Engineers.

10.3.5 H_2S Trim Equipment

10.3.5.1 Views of Canterra

Canterra stated that it would inspect all equipment at the time of spudding the well to ensure that it meets NACE MR 0175 and API standards. In general, it stated that all equipment which could be contacted by drilling fluids would be sour service rated. The company further stated that it would employ third-party inspection organizations to inspect drill pipe and it would replace components that could not be confirmed to be suitable for sour service. Mr. Sawotin, Canterra's drilling expert, stated that the high concentration of H_2S did not pose any special problem. Mr. McIntyre, Canterra's corrosion specialist, indicated that sulphide stress cracking was a function of the H_2S partial pressure and not a function of H_2S concentration alone.

Canterra said that although it would rely upon a third-party service company to perform some of the required testing, the company would also have a representative on site to perform inspections and ensure that all items were in compliance with sour service standards. The company also produced a copy of its standard drilling rig inspection check-list, and generally took the position that the high H_2S concentration did not pose problems that were not present at lower H_2S concentrations, particularly in relation to corrosion matters.

10.3.5.2 Views of Interveners

The Bergen Group, through Mr. Murray, expressed considerable concern about Canterra's ability to ensure that materials would meet sour service specifications and that all necessary maintenance would be looked after. He commented on the difficulty in finding a drilling rig that would meet all of the necessary criteria, and recommended that Canterra should have an expert in drilling equipment who would ensure that all equipment deficiencies were corrected and that all equipment would conform to the proper specifications.

Mr. Milo, on behalf of the Bergen Group, recommended a number of steps for a good corrosion-control program and also for a materials-selection program. He said that from what he had heard at the hearing, Canterra had a reasonable understanding of the potential problems and principles involved but had not demonstrated that it "recognized the importance of the follow-up procedures and the need to assign responsibility for implementing them". Mr. Milo stated these were very important and that the ability to maintain workable equipment under adverse conditions depended on having a program in place to recognize the problems and prescribe methods of dealing with them.

He suggested that acceptance of the common industry practice of labelling and spot checking as evidence of sour trim suitability was "grossly inadequate" for this application, and he further commented that it did not appear to him "that the knowledge or ability to furnish sour gas resistant material would be a major factor in the selection of the drilling contractor". Mr. Milo went on to say that the expertise appears to exist within the Canterra organization, as evidenced by its stringent sour gas line pipe specification, but that it needs to be implemented into a materials-selection criteria, a corrosion-control program for drilling, and in the rig-selection process.

10.3.5.3 Views of Board

The Board has reviewed the "Rig Safety Check List" as provided by the applicant, together with its statements and those of interveners. The Board is in general agreement with the interveners on these matters and believes that, to evaluate a rig and equipment for the intended service, Canterra will have to develop a full set of acceptance criteria and a detailed surveillance program. In the Board's view, the Canterra "Rig Safety Check List" is acceptable for general field inspections, but is not detailed enough for rig and equipment selection and material suitability for very critical wells like the one proposed.

If it approves the application, the Board would require as part of the final drilling program that Canterra outline its equipment selection and maintenance program in sufficient detail to satisfy the Board that these matters are not likely to create problems.

10.4 Safety Equipment

10.4.1 Views of Canterra

Canterra indicated that all normal oil-field safety equipment and procedures would be used. It stated that it was confident that the respiratory equipment now used by the company would be adequate in the event that high concentrations of H_2S were present in the atmosphere. However, it agreed that in the event of a release, H_2S concentrations could be higher around this well site than for the average one, but it had not done any special testing of the equipment. The company pointed out that it had considerable experience in the use of respiratory equipment at its various plant sites, including some potentially high concentration areas, and was convinced that the equipment was suitable for use at this location.

10.4.2 Views of Interveners

The Bergen Group, through Mr. Murray, expressed concern as to whether or not the proposed respiratory equipment was suitable for both SO_2 and H_2S, and whether all components were compatible with the environments to which they could be exposed.

10.4.3 Views of Board

The legislated responsibility for worker safety rests with the Occupational Health and Safety Division (OH&S) of Workers' Health, Safety and Compensation. The Board, however, is concerned that safety equipment and procedures must be adequate because failures in this regard could turn a minor drilling problem into a major one or perhaps a blowout. For this reason, the Board would, if it issues the requested well licence, contact OH&S for advice and direction as to whether Canterra's proposals respecting safety matters are adequate. To facilitate the review by OH&S, the Board asks that Canterra include in its final drilling program information respecting safety equipment and procedures.

10.5 Supervisory and Other Personnel

10.5.1 Views of Canterra

The applicant said that the staff assigned to the site would include one drilling engineer, one geologist, one mud engineer, two drilling supervisors and two mud loggers. In Canterra's view, assigning the above staff during drilling from 3100 m to total depth would be adequate. During this drilling period, two of the three senior drilling personnel (two drilling supervisors and the toolpush) would be on location, either on site or at the camp, 24 hours per day. While drilling the main hole beneath the intermediate casing at 3775 m, four safety personnel would be assigned to the operation. Well-site operations would be handled by one of the safety personnel and contingency planning would be handled by the other. The remaining two would be acting as a back-up crew to ensure no one works more than 12 hours without replacement.

It was indicated that all of Canterra's drilling personnel and all senior personnel assigned by the drilling contractor (rig supervisor and toolpush) would have valid Second Line Supervisor Certificates. One person holding a Second Line Supervisor Certificate would be be on site at all times. The driller, or anyone performing his duties, would have a valid First Line Supervisor Certificate[8]. All crew members would be trained in the operation of BOP equipment.

Canterra said that all personnel assigned to the location, including the drilling representative would be required to have Canadian Association of Oilwell Drilling Contractors H_2S Alert certification. Additionally, all personnel regularly on site (rig crews, contract personnel) would receive H_2S alert training at the rig prior to drilling out of intermediate casing.

10.5.2 Views of Interveners

Mr. Murray, on behalf of the Bergen Group, indicated that the required staff for the well should include two drilling engineers, two geologists, two mud engineers, two drilling supervisors, and two safety supervisors. He said that they would be necessary to ensure all aspects of the drilling operation would be properly supervised.

10.5.3 Views of Board

The Board accepts the personnel and their qualifications as outlined by Canterra to be generally satisfactory providing considerable on-site effort is made to ensure continuous awareness of potential problems and their possible impacts, and that senior expert advice is available at all times. The Board gave consideration to requiring, if the well were licensed, that such senior experts be on site while the critical zone was open to the wellbore. It decided that such a requirement was unnecessary provided experts are reasonably available for immediate contact, and so long as on-site personnel clearly understand that such people must be contacted at the first sign of a problem.

The Board, if it issues a licence, would have to be satisfied at the time the final drilling plan is reviewed that the staffing is in accordance with the intent expressed by Canterra at the hearing.

10.6 Drilling and Kick-Control Procedures

10.6.1 Views of Canterra

Canterra stated that the drilling program, as discussed through the course of the hearing, showed that it was prepared for and able to handle overpressured zones but that the expected pressures in the Leduc are less than would exist using a water gradient. Should high pressures be encountered, weight material would be on site. The applicant stated that it did not expect the Nisku Formation to cause lost circulation problems but it would be prepared to case off the Nisku before drilling the Leduc should problems occur.

Canterra stated that when drilling below 3100 m, the drilling fluid would contain an excess of 30 kg/m^3 of lime in the system to act as a buffer should any H_2S enter the wellbore. Tests would be performed on a frequent basis to determine if H_2S had entered and, if it was detected, corrective action would be taken by controlling the pH, use of H_2S scavenger, and corrosion inhibitors. A minimum of 200 sacks of H_2S scavenger would be on site, in case a large quantity of sour gas entered the hole.

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[8] A First Line Supervisors Certificate as issued to all persons who successfully complete the Canadian Association of Oilwell Drilling Contractors' course entitled Blowout Prevention & Well Control for First Line Supervisors.

Canterra said that third-party involvement in the selection and maintaining of the drilling fluids was not necessary due to the expertise available within the company, which would be performing pilot testing on the fluids and quality control testing of products to ensure no substandard materials were used. The pit volume totalizer planned for use on this rig would be a state-of-the-art computerized system.

The applicant stated that corrosion rings would be used in the drill string and stressed steel balls would be present in the drilling fluid to monitor corrosion rates and the presence of H_2S. It also said that the time-delayed float valve proposed for this well had been tested to ensure it met the manufacturer's specification. It had been used in two previous wells drilled by Canterra and a third well drilled by another operator, and performance was satisfactory.

Canterra recognized the potential for human error and said it would undertake to reduce this factor as much as possible. It would be performing BOP drills prior to drilling out of surface casing and at least once each 7 days thereafter. Another practice drill would take place at 3100 m prior to drilling through the Rock Creek Formation. Additional practice drills would be performed as required to ensure all members of the crew were proficient in their duties. The "driller's method" of kick control, as taught at the Petroleum Industry Training School (PITS), would be posted on location. All supervisors would also be familiar with other kick-control methods.

Any drill-stem testing of sour formations would be done as closed chamber tests, and would be performed through the casing to further ensure a successful and safe test. The applicant confirmed that such drill-stem testing would occur only if absolutely necessary.

In response to concerns from Mr. Murray, Canterra stated that testing a barite plug in the field was impractical due to the high likelihood that a complicated fishing job would result. It contended that other methods existed to control underground blowouts and stated that in other drilling operations, such an occurrence had been controlled without the use of a barite plug.

Although it did not intend to test run a barite plug, Canterra said the materials required for the operation would be on site and the drilling supervisors would be knowledgeable of the procedure.

10.6.2 Views of Interveners

Mr. Murray, representing the Bergen Group, detailed a number of concerns respecting well control, such as the lack of information on the chemicals and procedures to be used for corrosion control. He suggested that all such information to be contained in the final drilling program should be made public so that independent drilling experts could review it.

He expressed concern with the lack of testing of drilling fluids because the 90 per cent H_2S at the downhole temperatures and pressures could greatly effect its chemical properties and render the pit totalizers useless.

Mr. Murray stated that it was essential to maintain the pH of the drilling fluid at 10 to ensure the integrity of the drill pipe should sour gas invade the wellbore. He agreed with the use of scavengers on a continual basis and expressed the view that the pH should be checked at least twice per 8-hour shift. Mr. Milo suggested that on such a critical well, the pH of the mud should be measured hourly.

Mr. Murray indicated that there could be some problems in circulating out or weighting up gas-cut mud, and he also questioned the means by which the applicant would handle possible lost circulation in the Nisku or abnormal high pressures of the Leduc Formation. He said that Canterra should test run a barite plug to ensure that it has the knowledge and ability to handle this method of well control.

Mr. Murray emphasized that the mud system should be maintained and frequently tested by qualified personnel to ensure that the drilling fluid properties are not affected by H_2S contamination. He stated that if H_2S invaded the wellbore, it could cause the drilling fluid to lose some of its carrying capacity, thus lessening the ability to prevent a kick from occurring.

Mr. Murray said that the applicant had little experience with the proposed downhole time-delayed float valve and that a critical well was not the place to be testing relatively new equipment.

10.6.3 Views of Board

The Board believes that drilling procedures and kick-control methods are of vital importance and must be totally satisfactory before it would allow this well to be drilled. The use of extreme caution in essentially all operations within the critical zone is probably the most effective way to reduce the chances of a blowout. Training procedures and BOP drills, as generally outlined, appear adequate to ensure crew proficiency, provided they are effectively carried out and that crew awareness is kept at a high level. If the well is licensed, the final drilling program will have to assure the Board that Canterra will conduct all operations in the critical zone in a careful and demanding manner.

Generally, the Board agrees with Canterra's plans for the maintenance of the drilling fluid system, the use of excess lime and scavengers to neutralize H_2S should it enter the wellbore, the methods to circulate out a gas kick or deal with lost circulation, the pit volume totalizer, and the time-delayed float valve to be used.

Although the barite plug is one method of well control, the Board agrees with the applicant that a test run of this system could lead to undesirable hole problems, and notes that the material required to run such a plug would be on site if required.

If the well is drilled, the company may want to run a drill-stem test. While the Board believes that under proper conditions such a test could be safely carried out, at this time, it is not prepared to approve a test in the critical section. The reasons for this are the added risk, however small, of introducing well-control problems, or causing nuisance odours. Consequently, the Board would not allow a drill-stem test unless a subsequent application demonstrated a clear need and that the potential for problems would be small.

10.7 Detailed Drilling Plans

10.7.1 Views of Canterra

At various stages of the proceeding, interveners raised questions pertaining to specific technical items which were not addressed in detail in the application. Canterra, in response to many of these questions, indicated that the final drilling program would answer them. Canterra implied that it expected the Board to make decisions on such matters taking into account the comments of interveners. In response to a question, Mr. Martin indicated that very few parts of the final drilling program would be confidential.

10.7.2 Views of Interveners

Both the Bergen Group and Pioneer Lodge appealed to the Board indicating that in their view, the Canterra plans were not complete. Members of the public made general comments along the same line. This reference was to both the drilling program and the emergency evacuation plan.

In final argument, Mr. Miller, on behalf of the Bergen Group, requested that the community receive full and complete programs for the drilling of the well if the Board was prepared to grant the licence.

10.7.3 Views of Board

As already identified in other sections of this report, if it issues a licence, the Board would require Canterra to submit its final drilling program (and a final emergency procedures plan which will be discussed later) prior to commencement of drilling. Normally, these plans would be submitted to the Board and the Board staff would review them and then report to the Board who would make the final decision.

In this case, the Board believes it should go further if it issues a licence. The proposed well is expected to encounter a gas with 90 per cent H_2S; it is the first critical sour well to be reviewed at a public hearing since the Lodgepole Phase 2 report and critical well Draft Interim Directive were issued, and many concerns have been expressed by residents of the area. For these reasons, the Board would be prepared to establish a system whereby a copy of the final drilling plan, minus any proprietary information, would be made available for review by the public in the region. The Board would expect to receive comments from the public and would consider them in deciding whether the plans are adequate. Presumably, the public would wish to engage a drilling expert to comment and, if so, the Board would be prepared to pay reasonable costs.

10.8 Role of ERCB Field Staff if Well Licence is Issued

Little discussion took place at the hearing regarding the role of the Board staff with respect to the drilling of the proposed critical well should it be approved. The Board considers this to be an important matter and is aware that the staff, as a result of the Lodgepole Phase 2 report, is conducting a minimum of three inspections on critical wells. During these inspections, the staff ensures that all drilling equipment is properly functioning and that proper drilling and kick-control procedures are being followed.

As mentioned previously, the Board believes that the use of particularly careful procedures while drilling in the critical zone is one of the most effective ways of avoiding blowouts. To accomplish this, total crew awareness of potential problems and their consequences is necessary. The Board is of the view that a stepped-up role for its staff could assist in this regard.

Canterra indicated the likely time period in the critical zone would be about 30 days. (The length of this period is discussed further in section 11.) If the licence is issued, the Board would ask its staff to be present when the intermediate casing is drilled out, and thereafter to inspect the operations at least once per week while the critical zone is open. The Board would also require that Canterra report daily, by telephone to the ERCB area office. The report would indicate any problems that had been encountered, would confirm that daily inspections and drills were carried out, and, in order to facilitate an effective scheduling of

ERCB inspections, would generally identify planned operations during the coming 24-hour period. This requirement would be in addition to other functions required for critical sour wells.

The Board believes this increased staff involvement would be warranted given the particularly high expected H_2S content and the location of the proposed well.

10.9 Chances of a Blowout at the Proposed Well

10.9.1 Views of Canterra

During final argument, Canterra stated that "it and its predecessors have drilled over 1000 wells in the last 20 years, close to 300 of which were sour gas wells and have never experienced a major sour gas blowout during this drilling". Canterra also said that "no expert appearing as a witness in this hearing has said that this well cannot be drilled safely".

When questioned about the probability of a blowout at the applied-for well, Mr. Sawotin said that the 1 in 172 risk, as published in the Phase 2 Lodgepole report, was a historical figure but that there would be a major reduction in probability as a result of the new tighter regulations. Mr. Martin stated that the blowout probability for wells of unknown success would be less than 1 in 172, by the ratio of successful wells to all wells drilled.

Dr. Leahey also confirmed that he had used the 1 in 172 figure in his risk calculations and reduced it to 1 in 575 based on the assumption that only 30 per cent of wells drilling for sour fluids were successful.

10.9.2 Views of Interveners

Mr. Murray, for the Bergen Group, expressed the opinion that human error would be hard to eliminate and that this would be the key to eliminating blowouts. He referred to problems at other wells in the area and said that similar problems at the proposed well could make the risk of a blowout high.

Mr. Murray further commented that the industry should make a target of "zero blowouts" and unless this occurred "the government of the province is very likely to shut down sour gas drilling entirely in observance of adverse public reaction".

10.9.3 Views of Board

The Board has carefully reviewed the evidence presented as well as the statements made by participants regarding the probability of a blowout if this well were drilled. The Board believes that this matter is ultimately one of the most important considerations which has to be made when considering the application. The Board notes that when specifically questioned about the safety of drilling sour wells, Mr. Murray agreed, providing "parameters defined are met" that sour wells could be safely drilled.

The Board has reviewed the sour well blowout probability figure of 1 in 172 published in the Lodgepole Phase 2 report. The ratio cited is the number of sour well blowouts per successful well completed. Since not all wells which are exploring for sour gas find it, the historical number of sour gas blowouts per sour gas exploratory wells drilled would be much lower. Therefore, when the historical ratio of 1 in 172 is applied to an exploratory well, such as that proposed by Canterra, it must be altered to reflect the chances that the well would not be successful.

Canterra suggested the chance of success for the proposed well was 40 per cent, which, if applied to the historical ratio, would result in a blowout probability of 1 in 430.

The Board has not estimated a specific chance of success and thus an adjusted historical chance of a blowout for the proposed well because it believes that by far the most significant factor reducing the chances of a blowout are the special equipment and care to be taken in drilling. The 1 in 172, or 430, as adjusted, is based on history prior to the Draft Interim Directive which resulted from the Lodgepole inquiry. In this regard, the Board notes Mr. Murray's statements to the effect that he believed the proposed well could be safely drilled providing proper procedures were followed. The Board agrees with Mr. Murray and believes that this is the key item in reducing the probability of a blowout.

By applying closely supervised, well engineered plans, through the use of specialized equipment, and most of all by exercising extreme caution while in the critical zone, the probability of a blowout for this well, if it is licensed, would be reduced substantially.

The Board has reviewed the historical statistics regarding blowouts and their causes, using a typical fault tree network. It has assessed each of the causes of blowouts and attempted to estimate the impact on each of those causes of the special equipment and precautions that would prevail at the subject well. The statistics show that most kicks occur because of insufficient mud density or failure to keep the hole full while tripping, both of which reduce the pressure exerted against the formation at the bottom of the hole, swabbing of formation fluids into the wellbore by lifting pipe too quickly off the bottom of the hole, or lost circulation where the drilling fluids flow into a very porous formation. The Board believes that extra care and attention would have a major impact on these factors, particularly the failure to keep the hole full and swabbing which should be eliminated.

The statistics also show that the historical reasons why kick-control efforts have failed, resulting in blowouts, are equipment failures or improper control procedures. These kinds of problems cannot be totally eliminated, but prudently-designed equipment with adequate redundancy and a highly trained and well supervised crew, both of which would be specifically focused on during review of the final drilling plans, would greatly reduce the chances of a blowout.

A precise estimate of the probability of a blowout at any particular well is not possible. However, the overall conclusion which the Board has reached from its analysis is that the chances of a blowout at the proposed Canterra well would be significantly less than suggested by the historical data. Having reached this conclusion, the Board would not deny the subject application for a well licence on grounds that the well involves a high blowout risk. The Board emphasizes, however, that if there is any chance of a blowout, and there always will be, it would not allow the well to proceed if the impacts would be unacceptable, particularly from a public safety point of view. As a result, it will analyse those impacts in the following sections of the report along with actions which could be taken to mitigate them.

11 ACTIONS TO BE TAKEN IN CASE OF A BLOWOUT AND THE RESULTING IMPACTS

This section of the report, by necessity, details the circumstances that might exist if the proposed well was drilled and a blowout occurred. When the section is reviewed in isolation from the remainder of the report, it might give the impression that a blowout is to be expected. The Board emphasizes, as set out in the previous section, that this is not the case.

11.1 Actions to be Taken

11.1.1 Views of Canterra

Canterra submitted the general contents of an emergency response plan and said that if a licence is issued, it would prepare a detailed plan and review it with the public, seeking further input before it would be finalized. The key features of its proposed plan are described in the following paragraphs.

It would use a three-stage alert system.

- Stage 1 would be implemented if a kick occurred, and would involve notification and mobilization of company and government personnel to ensure they would be ready to act if a difficulty occurred in circulating out the kick.

- Stage 2 would be implemented if, when attempting to control the kick by circulating it to surface, a failure occurred in any piece of control equipment. At this stage, residents within the 4-kilometre (km) radius would be evacuated even though the well would not have blown out and efforts to control the kick would be continued.

- Stage 3 would be reached if the well was clearly out of control, at which time the complete emergency plan would be activated. Monitoring would take place and if levels of H_2S of 20 parts per million (ppm) or greater were detected beyond the 4-km radius, residents would either be evacuated or the well would be intentionally fired to convert the H_2S to SO_2.

Canterra said that if a kick occurred, there would likely be 2 to 3 hours before it reached surface and at least that much warning of an impending blowout should difficulties ensue.

The applicant said it has selected a 4-km planning zone as the largest practical zone. It would fire the well rather than try to deal with a larger area. It would use two mobile electronic H_2S/SO_2 monitors and would have them available at well site while drilling in the critical zone but did not see the need for monitors at individual residences.

Evacuation procedures would involve phone contacts and a mobile evacuation van to be stationed at the rig. A nurse would also be at the evacuation centre to advise the public. The evacuation centre would be the Town of Sundre (Sundre High School).

Appendix 4 shows the region surrounding the well, the proposed 4-km zone and the evacuation routes suggested by Canterra. In response to concerns respecting evacuation routes from the area, Canterra said it would construct two additional routes as shown in the appendix. Canterra said it investigated construction of a bridge across the river to the north but that such could not be justified because of the cost and the difficulty in providing road access.

The applicant stated that the on-site supervisor would have authority to fire the well if human life was in danger. This would be done automatically if an H_2S concentration peak of 75 ppm or a 30-minute average of 20 ppm was measured in an area that had not been evacuated, or if on any other basis, the on-site supervisor concluded that there was a threat to human life. Canterra said that a direction to automatically fire the well in case of a blowout would not be appropriate because damage from the ensuing fire might significantly extend the time needed to control the well.

The applicant anticipated no difficulty in igniting an uncontrolled release of 90 per cent H_2S gas which would be highly flammable within 20 to 30 feet of the exit point at the well. To ensure ignition would take place, Canterra proposed two ignition sources at the base of the rig which would be operated remotely via a flame ladder, with flare guns on site as a back-up.

11.1.2 Views of Interveners

The area residents individually and through the Bergen Group, the Pioneer Lodge, the Fallen Timber Group, and the Town of Sundre all expressed many concerns regarding the proposed emergency procedures plan. The residents considered the proposed 4-km planning zone inadequate and suggested that it meet the requirements of the Draft Interim Directive. They did not believe that the proposed ignition criteria were a suitable substitute for using a larger zone, and also questioned the use of Sundre as an evacuation centre because it is only some 9 km from the proposed well. Indeed, both the Town of Sundre and Pioneer Lodge said that the plan should consider the possible need to evacuate the Town of Sundre.

The local interveners were concerned that the number of evacuation routes in the area are limited, and may not be adequate to handle the volume of traffic during an evacuation. They referred to several situations where evacuation routes would take them past the well, for example, areas along the river where families outside the proposed emergency planning zone must enter the zone to escape the area, and the new proposed egress route for Pioneer Lodge which would be even closer to the well than the lodge is. The interveners suggested that a bridge across the Red Deer River is necessary to provide adequate egress from the area. Additionally, Mrs. Burton suggested that the new evacuation route to the north go through sections 17 and 18 rather than section 24.

The residents suggested that the applicant investigate a general telephone or other warning system because they foresaw great difficulty in ensuring that all people had been located and evacuated from the area. They said that procedures must be in place for searching for residents who cannot be reached by telephone, having in mind that the area includes dense brush and river valley flats, and that there could be deep snow at the time of an emergency. They also contended that one van was inadequate for assisted evacuations and should be increased to four.

Pioneer Lodge requested that adequate buses, with drivers familiar with the evacuation routes, be posted at the lodge while drilling the critical zone. It also asked that a contact person be posted there in case evacuation is required.

The local interveners pointed out that the emergency plan contains no provision for residents with health problems or for the elderly, who would find an evacuation traumatic. They requested a public health nurse to assist those who may be affected by the stress of an evacuation, and also asked that monitors be provided for the nearby residences.

The Bergen Group said that the plan should be expanded to address the concerns of local residents. They asked that they be given an opportunity to provide input to the plan, and to review the plan prior to approval by the ERCB. Pioneer Lodge stated that the plan should receive written approval from the county and Alberta Disaster Services prior to implementation.

The consultants for the Bergen Group presented evidence suggesting that there may be some difficulty in igniting the well. They said that even if ignition is possible, the ignition criteria proposed by the applicant is unacceptable because a decision based on monitoring data would not allow for a sufficiently quick decision.

11.1.3 Views of Board

Even if the possibility of a blowout is very remote, and regardless of the potential release rate, in this case the Board believes it crucial to public safety that means be provided to prevent a widespread dispersal of H_2S. To ensure this, the Board is of the opinion that if the well is licensed and drilled, and a blowout occurs, the most crucial action to be taken to protect the safety of the nearby residents is the ignition of the well.

Having reviewed the calculations and testimony of Dr. Leahey and Mr. Eichmaier regarding the distance from the wellhead at which the well effluent would be flammable, and the effluent exit velocity and the ignition temperature of H_2S, the Board is satisfied that the proposed ignition equipment would be adequate to ensure initial ignition of a release. However, the Board is concerned that the well might not remain on fire when first ignited due to the flow of drilling mud with the gas. Therefore, if the well is licensed, Canterra would have to satisfy the Board as part of the final drilling plan that it had devised a flare system with a remote fuel supply that would ensure that the well could be kept on fire.

Given the high H_2S concentration gas expected to be encountered, the uncertainty of the maximum potential H_2S release rate (as discussed in section 8), and the proximity and density of residents in the area surrounding the well (as shown in Appendix 4), the Board believes that any uncontrolled flow from this well would have to be ignited. This would convert the H_2S in the gas to SO_2, which, partly as a result of the thermal rise, would be more widely dispersed. The Board recognizes that this is a strong position to take and that immediate firing of the well would result in damage to the wellhead equipment which could lengthen the time necessary to cap the well. The question of public safety, however, must take precedence.

The Board would be prepared to make an exception to the mandatory firing rule only when a small leak of gas is occurring and conditions are such that there is good potential for regaining control of the well. Conditions would have to be such that control operations are proceeding, the leak is under continuous observation, and firing would be possible immediately should a further equipment failure occur. Also, as set out later in this section, certain areas in the vicinity of the well would have to be evacuated, and downwind monitoring would have to be taking place with the results showing no H_2S concentration greater than 20 ppm in any unevacuated area.

The Board has considered specifying the maximum time period during which a small leak would be allowed to flow without ignition, provided all the above conditions are met. Variables such as the location of the leak, the volume of gas escaping, and the condition of the control equipment make such a predetermination impractical. If such an event occurred, the necessity to ignite the leak would be under continuous review.

The Board considers the question of ignition criteria to be of basic importance in terms of all other actions that would be taken and of the impacts that could result from a blowout. Accordingly, if it issues the licence, the Board will set out the ignition criteria as a specific condition as follows:

A Responsibility for ignition will be delegated to and rest with the designated Canterra representative on site who will cause the well to be ignited under the conditions set out in clause B.

B The well must be ignited as soon as all personnel working at the site can be cleared to a safe distance under any of the following conditions:

  1 The well is experiencing an uncontrolled flow[9] and the well effluent has reached the surface.

  2 The well is flowing small volumes of sour gas to surface and is partially controlled but safety of residents cannot be assured because:

    (a) evacuation of residents within 1 km (the high-level emergency zone described later) has not been accomplished, or

    (b) monitoring results indicate H_2S levels that exceed 20 ppm in unevacuated areas, or

    (c) monitoring is not taking place due to some unforeseen circumstances, such as weather.

With respect to the ambient air monitoring to be conducted during the critical phase of the well, the Board believes that two mobile electronic monitoring units should be stationed at the rig during the critical phase of drilling so that they can be positioned downwind to commence monitoring at the first indication of a problem. With the ignition requirements set out earlier and the alert and evacuation criteria set out in the following sections, there is no need for monitoring units stationed at individual residences.

With respect to the three-stage alert and evacuation program proposed by Canterra, the Board sees merit in such an approach but believes that it should be amended from that submitted. The revised alert stages would be as follows:

- Stage 1 would be implemented if a kick[10] occurred and would involvenotification and mobilization of company and government personnel to ensure they would be ready to act if a difficulty occurred in circulating out the kick. Additionally, electronic monitoring equipment which would be required at the rig during the critical period would be dispatched to the downwind areas for possible monitoring.
- Stage 2 would be implemented if, when attempting to control the kick by circulating it to surface, a failure occurred in any piece of control or circulating equipment. At this point, the full sour gas response emergency plan would be implemented in order that all personnel and facilities would be in place should an uncontrolled release occur.
- Stage 3 would be reached if a small leak of sour gas occurred and conditions were such, as described previously, that the leak would not have to be ignited. If the leak was ignited, it would almost certainly lead to complete loss of control and a Stage 4 situation.
- Stage 4 would be reached if the well was out of control at which timeit would be ignited if it was not already on fire.

Having set out the ignition criteria and the four-stage alert system required, the Board will next address the question of emergency response planning areas. The Board does not fully agree with the H_2S release rate calculated by Canterra, nor does it consider the 4-km planning area around the well fully adequate. At the same time, given the unusual ignition requirements that would in this case be attached to any well licence issued, the Board recognizes that the emergency planning area does not have the same meaning as is normally the case.

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[9] "Uncontrolled flow" and other terms are defined in Appendix 6.

[10] Also includes any other severe drilling problem such as lost circulation or stuck pipe.

In this particular situation, the Board believes a series of concentric areas, illustrated on Figure 2 (Appendix 4), should be established around the proposed well, each of which would be part of the emergency planning area. They would not, however, all require the same level of emergency activities.

An inner ring of 1-km radius closest to the proposed well would be established as the high-level emergency zone. Next would be medium-level emergency zone comprising the area between the high-level zone and a 4-km radius circle. The 4-km circle would be extended to the northwest of the well to the Red Deer River in the northern part of section 10, section 15, section 22, and section 23, all in township 32, range 6, west of the 5th meridian. These sections contain several residences without egress from the area except to go past the proposed well site.

The final concentric ring of the emergency area would extend to 8 km, double the distance to the 4-km medium-level emergency zone. This low-level emergency zone from 4 to 8 km from the proposed well is considered an added precaution in view of the requirement that an uncontrolled release would have to be ignited. Although somewhat irrelevant in view of the requirement for ignition, the 8-km distance is also the approximate distance to the calculated 100-ppm H_2S isopleth under worst conditions, without ignition, at a release rate of 6 m^3/s. The Board believes it important to note that the isopleth calculation assumes worst conditions and is very conservative in nature.

The requirements that would apply to the three zones are summarized in Table 2 and would be generally as follows:

High-Level Emergency Zone (1 km) – Zone 1

Residents within this area would be provided with an H_2S information package, would be visited to ensure they understand the program, and would be kept fully aware of activities at the well during drilling of the critical zone. In the case of a kick or other severe drilling problem (Stage 1 alert) they would be advised so that an evacuation, if necessary, could be quickly accomplished. The evacuation would take place as a first priority off-site action if any problem occurred during efforts to control the kick (Stage 2 alert). Even though immediate ignition would be required in case of a blowout, or of a leak if public safety could not be assured, the evacuation would take place as an extra precaution because of the proximity of these residents to the well and uncertainties that always accompany emergencies. The zone would have to remain evacuated until the well was fully under control or, if the well was on fire, until monitoring for SO_2 and other relevant information clearly demonstrated that there was no safety reason for keeping the area evacuated.

Medium-Level Emergency Zone (beyond the 1-km high-level zone to approximately 4 km) – Zone 2

Residents in this area would receive the H_2S information package and would be visited to ensure they understand the program. They would be notified if a problem occurs during kick-control procedures (Stage 2 alert) and any particularly sensitive individuals (the ill, elderly, or very young) would be evacuated. These individuals would have to be identified as part of the detailed emergency planning process. At this particular stage, which would be prior to any actual blowout, the Board believes that other persons who wished to leave the area should also be evacuated. This would be done primarily for the peace of mind of the individuals because with the ignition requirements as discussed previously no threat to life should exist. The only times that evacuation would be essential is if the well was blowing out of control (Stage 4 alert) and in the extremely unlikely circumstances where either it could not be ignited or kept on fire or the equally unlikely case where it was burning but monitoring results showed high levels of SO_2. For this purpose, a high level of SO_2 would be 1 ppm for 2 to 3 hours or 0.3 ppm average over 24 hours.

In the event of a small leak of sour gas (Stage 3 alert) where the well is not out of control and monitoring shows no threat to human life, all residents in this zone out to about 4 km should be evacuated to provide Canterra with additional time to try to fully control the well before igniting it. The object in this case would be to quickly control the well and avoid a prolonged emission of SO_2 from a burning well. Following an evacuation, the return of evacuated people to their homes would depend on well-control operations and the results of monitoring.

Low-Level Emergency Zone (beyond 4-km medium-level zone to 8 km) – Zone 3

Residents in this zone would receive the H_2S information package. There is little possibility that special action would be required for people in this zone except for sensitive individuals who should have been identified during the planning process. They would be evacuated if any problems were encountered during kick-control operations (Stage 2 alert). Also, if the problems were not successfully overcome and the well blows out (Stage 4 alert), those in this zone who wished to leave would be

TABLE 2 SUMMARY OF EMERGENCY PLAN BY ALERT STAGE AND ZONE

Alert Stage	Well Condition	Zone 1 1-km radius	Zone 2 4-km radius and northwest	Zone 3 8-km radius	Additional Action
0	No problem	Information package + visit + awareness of activities	Information package + visit	Information package	–
1	Kick or other severe drilling problem	Evacuation alert	–	–	Notify and mobilize company and government personnel. Dispatch air monitors downwind.
2	Control equipment failure while circulating kick	Evacuate	Information alert. Evacuate sensitive people and those who wish to leave.	Information alert. Evacuate sensitive people.	Initiate sour gas release emergency plan.
3	Small sour gas leak – not ignited	Evacuated	Evacuate remainder of people.	Evacuate those who wish to leave.	Monitor downwind area and ignite if public safety cannot be assured.
4	Uncontrolled flow	Evacuated	Evacuate* if burn not continuous or if SO_2 levels high	Evacuate if burn not continous or if SO_2 levels high	Ignite immediately

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* Zone 2 may already have been evacuated if a Stage 3 alert had been in effect.

evacuated. As would be the case for Zone 2, in the highly unlikely event of a blowout where it was not possible to keep the well continuously on fire, or where monitoring results showed high SO_2 readings as defined above, Zone 3 would be evacuated.

The previously described evacuation requirements for the emergency response area are in addition to those provincial guidelines for action regarding H_2S established by the Alberta Provincial Board of Health.

The Board has considered the matter of the number of evacuation vans and believes that the availability of four vans to assist with evacuation should be sufficient. Canterra has agreed to supply buses with drivers knowledgeable of the evacuation routes to Pioneer Lodge while drilling in the critical zone. A contact person is also to be supplied. The Board believes that these measures would be adequate.

The Board notes that Canterra has agreed to supply the services of a public health nurse during the critical phase of the well, in order to counsel or assist the elderly or those with health problems.

The Board recognizes the concerns expressed by the residents regarding the routes for evacuation from the area. The Board also notes that many of the residents must travel toward the well in order to evacuate, especially in the areas north and northwest of the well. The applicant has agreed to construct or provide for egress which would maintain more separation distance between residents and the well during an evacuation. These routes are shown on Appendix 4.

The Board has reviewed the available routes, those proposed by Canterra, and the concerns expressed by the interveners, including those respecting the need for a new bridge north across the river. Because of the strict ignition criteria and the reduced reliance on evacuation for safety, the Board is satisfied that Canterra's plans are acceptable. Even though the Board believes that it is unlikely that residents in the low-emergency zone to 8 km would ever have to be evacuated, it believes the company's final plan should include specific egress information for those areas where there are limited options.

The Board wishes to emphasize that a comprehensive review of the final emergency procedures plan will be done prior to its approval. In addition, in this case, the Board is prepared to establish a system which provides for comments from the public to the Board on the final plan. The Board would expect that this input could be accomplished primarily through meetings with residents in the area. It would be prepared to defray the costs of an expert adviser for the residents if they so desired.

11.2 Plans for Capping Well

11.2.1 Views of Canterra

Through rebuttal evidence, Canterra stated that in its opinion the prefiling of well capping procedures would be a hypothetical and largely futile exercise. The applicant indicated that if the well blew out, the actual capping procedures would depend on many variables which would be impossible to predict in advance. It said that the structure of its organization would allow for the effective handling of control operations and planning for a relief well should such be needed.

Canterra expressed, the opinion that a relief well, if needed, could be commenced in 7 to 14 days following a blowout. The applicant also stated that the surface location for the relief well would be prenegotiated.

11.2.2 Views of Interveners

Mr. Murray, for the Bergen Group, expressed concern that should the proposed well blow out it would be very difficult to regain control. It was suggested that very little experience exists worldwide in the procedures to be used to cap a well with 90 per cent H_2S, whether it was ignited or not.

Mr. Murray expressed an opinion that the drilling of a relief well had as much a chance of being unsuccessful as it did of being successful. A concern was expressed that obtaining the licence for the relief well could be a lengthy process if a hearing was required.

11.2.3 Views of Board

While the Board is confident that the proposed well could be drilled without problems, it recognizes the potential problems of capping a wild well. However, it agrees with the applicant that little would be gained by preplanning in detail such an operation. Rather, the planning efforts should focus on preventing a blowout. However, an emergency response plan should lay out the lines of authority and steps to be taken to ensure that control operations would be promptly implemented.

The Board also recognizes the potential problems of drilling a relief well. Should such a well be required, the licensing and initiation of the drilling operation could be done in the time frame suggested by the applicant.

11.3 Impacts of a Blowout

As indicated in the previous section, if the proposed well was licensed and drilled, the Board believes the probability of a blowout would be very low. However, before it decides whether a licence should be issued, it considers it necessary to evaluate how serious the impacts of a blowout would be. The previous subsection deals with numerous actions to be taken in the event of a blowout. Many of them would be to mitigate the impacts, and the basis for this section of the report is that the actions would be taken. The most crucial action in terms of potential impacts on the public is the ignition requirement which the Board would impose on Canterra if the licence is issued.

11.3.1 Views of Canterra

The applicant stated that the impacts of H_2S on residents in the area would be minimized by the proposed ignition and evacuation procedures. Canterra said that it would initiate an evacuation if there was a failure of kick-control equipment during any kick-control operations, and also would ignite an uncontrolled release at an early stage.

The company's risk consultant, Dr. Leahey, presented an analysis to demonstrate that the residents would be exposed to only a very low level of risk from H_2S if a blowout occurred and the proposed evacuation and ignition procedures were followed. He also expressed the opinion that there would be no adverse effects from levels of H_2S to which residents might be exposed. Dr. Leahey did, however, agree that the toxicity assumption in the analysis may not be appropriate if the area residents contain a particularly high proportion of persons more susceptible to H_2S than the average. He also presented modelling results that showed a possibly worst-case rapid movement of the plume in 27 minutes to Pioneer Lodge and 74 minutes to the Town of Sundre. Dr. Leahey acknowledged that H_2S will, in some meteorological circumstances, tend to move along the ground and to disperse less quickly in low areas.

The applicant's view regarding emissions from the well subsequent to ignition was that evacuation due to SO_2

should not be required, nor would any hazard to health occur. Dr. Leahey said, based on the flammability of H_2S, that 100 per cent conversion to SO_2 is a reasonable assumption and H_2S should not be of concern after ignition. He indicated that SO_2 is of similar toxicity to H_2S, but the large thermal rise from the combustion of the plume would produce better dispersion and result in much lower ground-level concentrations than for H_2S from the unignited plume.

Dr. Leahey presented the results of dispersion calculations for the ignited plume, which predicted concentrations of SO_2 below the occupational exposure limits (OEL). He predicted, because the model is conservative, an actual maximum SO_2 concentration of approximately 0.06 ppm with maxima occurring on approximately 12 days, assuming a possible 120-day blowout period. He expected that such SO_2 concentrations would be below the odour threshold but above the taste threshold.

Canterra agreed to gather and disseminate information on the health effects of low levels of SO_2 to the local residents. Should the area be subjected to low level concentrations of SO_2, Canterra would seek information from any residents perceiving health effects.

The applicant presented a panel of experts to address the impact of an uncontrolled release on the local water systems, both surface water, including the Red Deer River, and the shallow aquifers which are the water supply for local residents. Members of the panel testified that a very minimal impact, possibly below the present range of possible measurement, would occur. They discussed such factors as the low solubility of H_2S, the low expected atmospheric concentrations of SO_2, the high buffering capability of the local soils, and the dilution effect due to the large size of the local aquifer to support their view.

When questioned regarding the impacts of the Lodgepole blowout on water, the experts attributed the groundwater effects to condensate, and indicated that the proposed well effluent is not expected to contain condensate. The experts did not foresee any health impacts from use of the local water nor any change in water availability as a result of drilling the well, even if it blew out. In addition, Canterra made a commitment to monitor all water wells within a 4-km radius of the proposed well, including sampling and flow testing.

In response to concerns of area residents that the well be drilled during the time of year when impacts would be minimized, Canterra said that it had no preferred season to drill the well, only that it would like to begin as soon as possible.

The applicant stated that compensation would be paid where the company was found responsible for damages. This was agreed to for cases such as evacuation expenses, loss of livestock, and loss of land value including vegetation. The applicant did not consider posting of a performance bond necessary.

11.3.2 Views of Interveners

The Bergen Group and other local interveners expressed concern regarding the toxic levels of H_2S that would be released by a blowout of the proposed well. The level of risk associated with the facility was felt to be unacceptable. They questioned some of the assumptions made in the risk calculations, such as the concentration at which H_2S is fatal, and the use of flat topography notwithstanding the Red Deer River valley. The residents also questioned whether adequate consideration had been given to those who might be more sensitive to H_2S, the elderly, the very young, and those with health problems. The Town of Sundre expressed concern that the residents of Sundre could be exposed to potentially lethal concentrations of H_2S if an uncontrolled release occurred. It also indicated a concern regarding the general environmental impact of the well, and requested that an environmental impact assessment (EIA) be prepared prior to spudding. An additional concern was voiced for the safety of the livestock, which would be left behind if it was necessary to evacuate the area.

Residents also expressed the view that discomfort from the odour of H_2S is an important consideration, and that a commitment should be made by the applicant to ignite an uncontrolled release after some maximum time period.

Mr. Cloakey expressed the view that people and animals in the Bergen area exhibited health symptoms from both the H_2S and SO_2 emitted during the Lodgepole blowout. He felt, as a result, that the 20-ppm evacuation criteria for H_2S is too high, as it does not take short-term peaks into account, and relates to workers – not those who may be more sensitive.

The local interveners also expressed concern regarding possible health impacts from the low levels of SO_2 that would result from ignition of the proposed well if a blowout occurred. The residents were concerned about the health effects reported and experienced during the ignited phases of the Lodgepole blowout. Several said that a large proportion of local residents had moved to the area because of concerns for health, and that the area might contain a higher than average number of more sensitive people.

Mr. Grimstead expressed concerns regarding SO_2 and based them on his experience with discomfort from emissions from existing wells in the area where sour gas is burned.

The local residents questioned whether existing studies into the health effects of low level emissions of H_2S and SO_2 were conclusive. They pointed out that causes of illness are often difficult to determine, and that chronic illness from emissions would occur for a long period of time before the cause could be identified. Mr. Grimstead pointed to an absence of information available regarding the health effects of H_2S and SO_2 at low levels, and recommended that more studies be done. Mrs. Halvorson also noted the lack of such information and Dr. Bauman expressed concern that no medical witness was present to discuss the health effects of SO_2 or H_2S.

The bulk of the concern regarding the impact of the well on potable water supplies in the area was expressed by the Red Deer Regional Planning Commission (Commission), on behalf of the City of Red Deer and other communities, and the Town of Sundre. The Commission was concerned that an adverse impact on the quality of water in the Red Deer River would affect the water supply of a large number of downstream communities. It stated that even a minimal impact would not be acceptable, but did not define what would be considered a minimal impact. The Town of Sundre also expressed concern with potential impacts on the Red Deer River.

Mrs. Burton requested that the applicant expand the radius of the proposed testing program for water wells in the area.

The Bergen residents were concerned that the impact of a blowout would be more severe during certain critical periods in their farming operations. The period of most concern was during calving and foaling from January to May and during the summer when outdoor work and recreation would make evacuation more difficult. Pioneer Lodge said that its period of lowest use was in late fall. It gave June as a second choice, provided that drilling would be completed before July. Mrs. Halverson gave June and November as preferred months for drilling. Mrs. Worobetz had concerns year round, but particularly in winter when the area experiences heavy wet snow and evacuation may be impossible, in spring during calving, and in early summer during foaling and breeding.

There appeared to be general agreement among the local interveners that if the well had to be drilled, October and November would create the least impact on them and their operations in the area.

Many of the area residents questioned Canterra regarding compensation for various losses and damages that might result from a blowout. These included loss of and injury to livestock, loss of land value including damage to vegetation, evacuation expenses, and loss of income due to a disruption of normal activities. The residents also made several suggestions as to how such losses might be compensated. The Bergen Group requested that the applicant provide a written guarantee of compensation for any damages that might occur. Pioneer Lodge recommended that a performance bond be posted to compensate residents.

11.3.3 Views of Board

The Board recognizes the concern of the local residents regarding the toxic levels of H_2S that could be released from a blowout of the proposed well. The Board has examined the risk calculation provided by Dr. Leahey, and although it believes the calculation is as accurate as current technology allows, it does agree with the interveners that there is a significant degree of uncertainty in many of the inputs to the calculation. It is for this reason, coupled with the maximum potential release rate and the number of residents in the area, that any blowout must be ignited immediately unless there is partial control of a small flow and regaining full control is imminent and nearby residents have been evacuated (as under conditions defined earlier). In these circumstances, that is with a mandatory ignition of any blowout, the Board believes that the impact of H_2S on the public or the surrounding area would not be significant.

The Board has examined the SO_2 dispersion calculations provided on behalf of the applicant by Western Research. The predicted concentrations indicate that the Alberta air quality standards for SO_2 (Clean Air Act Maximum Levels Regulation) may be exceeded if certain adverse atmospheric conditions existed. However, under the worst of these conditions, the predicted SO_2 concentrations are approximately half of the maximum allowable under Occupational Health and Safety Act, Chemical Hazards Regulation. Although the Board believes that it is highly unlikely that evacuation due to high SO_2 would be necessary if a blowout occurred and the well was ignited, SO_2 concentrations under adverse conditions could make it necessary to evacuate some areas and therefore monitoring would be required.

Canterra has asked that in such an event, it be informed of any adverse health effects from SO_2 experienced by residents. The Board recognizes that sensitive individuals could experience difficulties even though concentrations would be low, and would expect such effects to be promptly investigated by the local medical authorities, and such residents be evacuated from the area at Canterra's expense.

The Board is satisfied that minimal impact on the area's surface and groundwater is to be expected if a blowout occurs. Little or no condensate is expected in the effluent of the proposed well, and the majority of negative impacts on water systems seen in previous blowouts were due to condensate.

The Board also agrees with the applicant's intention to perform water quality and flow testing on all water wells within 4 km of the proposed well. The Board sees no necessity of extending the tests beyond that distance because it is satisfied that such outlying wells would not be affected.

The Board agrees with the interveners that there is presently a lack of data regarding the health effects from long-term exposure to low levels of H_2S or SO_2. Even though the matter of air quality standards is beyond the jurisdiction of the ERCB, the Board knows that the existing ambient air quality standards were set in order to prevent health effects. Indeed, the standards imposed are actually nuisance standards rather than health standards and are equal to the most demanding in the country. It should be noted that occupational health standards allow sustained H_2S levels of 10 ppm for 8 hours per day which is 1000 times higher than the level provided for in provincial air quality standards.

The Board notes the concerns expressed by the local residents regarding the timing of the drilling of the well and their contention that if the well must proceed, it should be drilled at the time of year that would present the least negative impact on the surrounding residents if a problem occurred. Comments were made regarding calving and foaling in the spring, outdoor work and recreation during summer, and difficulty with evacuation due to heavy snow in winter. There appeared to be some consensus among local interveners that the most appropriate time would be during the late fall. The applicant expressed no difficulty with drilling at any particular time of year, but urged that it be allowed to proceed as soon as possible.

The Board has analysed the schedule that might be followed if it was to issue a well licence in early January 1985. The Board estimates that the elapsed time required to prepare final drilling and emergency response plans, have them reviewed by the Board and the public, obtain Board approval of the plans, contract for and move in a rig, and drill to the critical zone and set intermediate casing might take 6 or 7 months. This would mean operations in the critical zone in the July or August period, and an imposed delay to late fall would translate into about 3 months. Given the circumstances that this would be the first very high H_2S well drilled subsequent to a public hearing since the release of the Lodgepole inquiry report, and the many concerns expressed by residents of the area, the Board does not consider that the approximate 3-month delay would be unreasonable. Accordingly, if it licenses the well, the Board would require that the timing of the drilling be such that the critical zone would be open only during October or November.

On a related matter, since the only period of serious concern is when the critical zone is open, the Board will require Canterra to investigate ways in which it could reduce that time. It believes that the 30-day period could be reduced and would require the company to give reasons in the final drilling plan as to why each proposed operation in the critical zone is neccessary.

Regarding the matters of compensation and a performance bond, the Board has reviewed the legislation under which it operates and the Canterra application was filed. On the basis of the review, it has serious doubts as to whether it would have jurisdiction to condition a well licence with a requirement for the posting of a performance bond. This, coupled with the size and resources of the applicant company, Canterra, the legal obligations which the licence would impose on it to control any blowout and to protect the public, and its undertaking at the hearing to accept financial responsibility for any damage that was caused by its operations, results in a conclusion by the Board that a performance bond condition to the licence would not be appropriate.

The Board does understand the concerns expressed by certain residents of the area regarding possible costs to them of impacts should a blowout occur. Comments from some of the interveners appeared to recognize that if a blowout occurred and financial impacts were proven, a settlement would be made. Their concerns, however, apparently relate to the burden of proof being on the public, the relative costs of that burden, and the lengthy delays that would likely occur. Concern was also expressed that the nuisance effects of a blowout, and indeed the fear that one might occur and the resulting pressure and anxiety that residents of the area would be subjected to if the well was drilled, were items that should be compensated for but would not be under the existing civil liability system.

Suggestions were made that Canterra be required to carry blowout insurance. This seems to imply an expectation on the part of some residents that a form of no-fault third-party-damage insurance would eliminate deficiencies which they saw in the present system. The Board is not certain that this would be the case, but notes that the Lodgepole Blowout Inquiry Panel recognized a possible problem of this nature and recommended study of the matter by the ERCB, industry, and concerned government departments. Such a review is currently under way.

11.4 Summary Views

Having reviewed all of the evidence concerning actions to be taken in the event of a blowout and the resulting impacts, the Board concludes that the impacts of a blowout would not be disasterous to the public provided the appropriate actions are adequately planned for and properly executed if a blowout occurs. The Board cannot overemphasize the importance it places on the actions which must be taken in such an event, particularly with respect to ignition of the well. As indicated in the preceding section, the Board is satisfied that the applied-for well can be drilled safely, however, even in the unlikely event of a blowout, it believes resulting impacts can be minimized and kept to an acceptable level.

12 TEST PHASES AND LIKELIHOOD OF FURTHER DEVELOPMENT

12.1 Testing

12.1.1 Views of Canterra

The applicant said that an as-yet undetermined period of flaring would be required for the testing of the proposed well. It did not believe that further testing of the existing Bearberry well would provide adequate information as to the capability of the proposed well.

Several alternatives to flaring which are presently available, including on-site processing of the gas, had been examined by the applicant but dismissed as impractical. It did agree to consider the possibility of piping the test production to a more remote location for flaring.

Although Canterra has not yet been able to form an estimate of the period of testing that would be required, it agreed to minimize the period of flaring, and to dilute the well effluent with fuel gas, if necessary, to meet the SO_2 ground-level standards.

12.1.2 Views of Interveners

The Bergen Group and other local interveners expressed concern with odours that might result from the testing of the well. They related past unpleasant experiences with odours from the plant or wells in the existing Harmattan-Elkton Field, and expressed concern regarding possible health effects from exposure to the plume, especially to more sensitive individuals.

The Bergen Group recommended that all steps possible to reduce odours be taken, and that all odour complaints be handled immediately. Mr. Grimstead stated that if the existing facilities in the area are presently meeting the SO_2 ground-level air quality standards, then the standards are too lenient because he has experienced discomfort from odours from them.

12.1.3 Views of Board

Since the present application deals with a licence to drill the proposed well, the Board is not in a position to make a decision respecting possible testing. If the well is drilled and such an application is made in future, the Board would examine in detail the matter of flaring effluent from the well.

An application, if made, would have to deal with possible alternatives to flaring, the period of flaring and steps to minimize it, steps to prevent a violation of the H_2S and SO_2 ground-level standards, the extent of planned downwind monitoring, and actions to be taken in the event of a violation or an odour complaint.

12.2 Likelihood of Further Development

12.2.1 Views of Canterra

Canterra said that if the proposed well was successfully drilled, the well effluent would likely be transported via pipeline to the Ram River gas plant and suggested three possible pipeline routes. Canterra acknowledged that sulphur plugging can be a critical problem in gathering systems but stated that it has been successful in solving this problem in other high H_2S wells. It stated that the amount of sulphur solvent in the pipeline along with that in the produced fluid would be sufficient to dissolve any additional sulphur that might come out of solution. Canterra also said that the solubility of sulphur is significantly higher in liquid than in gas and it would therefore keep the fluid in its liquid form to reduce the risk of precipitation in the pipeline.

Canterra submitted that its preference for processing the gas from the well would be at the Ram River plant because excess capacity would be used and the regeneration of the solvent at Ram River rather than at the well site would be more desirable from an environmental point of view. Canterra stated that if it had difficulties transporting the fluid to Ram River, its second option, which it acknowledged as possible, would be to build a gas plant in the area. It also said that there was a possibility of more wells being drilled in the area, some by other operators, and their preference for processing the gas is completely unknown.

Canterra submitted that if the proposed well is completed, the production facilities at the well site would probably include a separator, a utilities package, an enclosed sulphur solvent system, a supervisory control system, and a back-up power system. The enclosed sulphur solvent system should prevent the rather odoriferous solvent from escaping and annoying residents in the area. Canterra acknowledged, however, that there could be occasions where it would be necessary to truck solvent to the well site and odours might escape.

The well-site equipment would be computer controlled by a system located on the lease but the operation would be remotely monitored and inspected daily by a company representative. Thermal detectors located at the well site would, in the case of fire, set off an alarm in the control room at the Ram River plant and the well could be shut in remotely. In the event of a power failure, the battery pack planned for the well site would have enough capacity to run the instrumentation on the lease for a few days. Canterra stated that there would be no continuous emissions from the well site, although there could be occasional leaks which, upon being detected, would be immediately fixed.

Canterra said that in the event a licence is issued and a successful well is drilled, it is prepared to accept the risk that it might not receive approval for the testing, pipelining, or the processing of the gas.

12.2.2 Views of Interveners

The Bergen Group stated that processing the gas at Ram River would be far superior to the well site, provided the well effluent could be maintained in the liquid phase while transporting it to the plant. The group stated that regeneration of the solvent and processing of gas at the well site could cause H_2S and SO_2 pollution problems.

The Bergen Group also identified a number of concerns it had even if the gas was processed at Ram River, including odours from the transport and use of solvent, corrosiveness of the solvent/liquid H_2S mixture, phase separation and liquid hold-up in the gathering system, the risk of pipeline rupture, design of the block valve spacing, and flaring under normal and emergency conditions.

12.2.3 Views of Board

The Board does not have applications before it for possible subsequent phases of the project and accordingly cannot deal with them. It is looking at these matters in only a general sense in that it would likely not issue a well licence if evidence clearly indicated that production from the well was impossible. At the same time, it is necessary to emphasize that approval of the well licence application does not assure that subsequent facility applications would be approved.

Generally, the Board is satisfied with the explanation of possible future development in connection with the proposed well. The Board believes that there are a number of technical matters which would have to be dealt with at the appropriate stage of development but there is a reasonable chance that acceptable solutions would be available. The Board expects that a well of this nature would be state-of-the-art as far as remote operation, equipment redundancy, and security is concerned.

It generally appears that a suitable pipeline route could be found and this would have to be evaluated along with its technical design and operation at such time as an application is made.

The Board recognizes that the successful drilling of the subject well could lead to licence applications for other wells in the area. The issuance of a licence for this would not necessarily mean subsequent applications would be approved. This would depend on the assessed merit of the applications at the times they were made.

13 FINDINGS

The Board, having regard for its responsibilities under the legislation, and its reviewing of the extensive evidence presented, finds as follows:

1. Canterra has leases in the area of the proposed well and the right to explore for minerals.
2. There is a good chance that the proposed well will prove up reserves of very sour natural gas and provide an opportunity to test, on a site-specific basis, the proposed technology for producing such reserves.
3. The well should not be drilled if other tests in the province of the production technology take place and suggest that there is little likelihood of it being successful.
4. It is difficult to estimate the maximum potential H_2S release rate for the proposed well, but on the basis of a test at the nearby Bearberry well, and using a conservative approach for purposes of planning for the safety of the public, the H_2S release rate could range from 6 to 15 m^3/s.
5. There are no unique or serious problems to be expected in the "non-critical" portion of the proposed well, above 3775 m, and intermediate casing will be set at that point. Care is necessary to preserve the integrity of that casing because it could be crucial if problems developed while drilling in the potentially high H_2S section of the well.
6. The geological prognosis does not suggest that particularly serious problems, such as overpressured zones, would be encountered while drilling in the Nisku and Leduc formations, the critical section of the proposed well. Nevertheless, caution is required because of uncertainties as to what will be encountered.

7. The Board is satisfied with the casing program planned for the proposed well.

8. The Board is generally satisfied with the BOP equipment planned for the proposed well; however, inspection and testing of the equipment is very important and must be detailed for further review in the final drilling program.

9. The overall plans respecting the mud system are satisfactory but more detail will be required in the final drilling program. Additionally, a volume of ready-mixed mud equal to 150 per cent of the volume of the hole should be available at the time the intermediate casing is drilled out.

10. The Grade E drill pipe planned by Canterra is acceptable, provided care is taken respecting inspections and maintenance of it. Details respecting these matters would be required in the final drilling program.

11. The proposed kick-detection equipment is generally satisfactory. The use of such equipment, however, is equally important as the equipment itself, and both of these matters should be further detailed in the final drilling program.

12. Detailed procedures are required to ensure that all equipment which could come in contact with H_2S at the proposed well would meet H_2S specifications. The final drilling plan would have to detail the manner in which this would be done.

13. Canterra's plans respecting safety equipment and procedures appear reasonable; however, the detailed plans to be included in the final drilling program will be reviewed with the OH&S Division of Workers' Health, Safety and Compensation to ensure such is the case.

14. Plans respecting supervisors and other rig personnel are generally satisfactory but the final drilling program must elaborate on procedures that will be used to ensure that the well-site personnel are totally aware of the importance of avoiding problems, and to ensure that experienced advice is readily available and will be accessed when needed.

15. Drilling procedures and those planned to control a kick, should one occur, are of vital importance in terms of avoiding a blowout at the proposed well. Canterra's plans in this respect are generally satisfactory but require further attention in the detailed drilling program, particularly with respect to staff training and drills to ensure that procedures are fully understood and that caution will be exercised in all important operations.

16. A drill-stem test of the critical zone at the proposed well should not be conducted unless Canterra can demonstrate a clear need for such a test and that potential problems can be adequately handled.

17. The final drilling program should be made available to the public for review so that the public may submit comments to the Board. The Board would be prepared to defray reasonable costs for a drilling expert to advise the public of the Bergen area in this regard.

18. ERCB involvement in and inspections of the drilling operations at the proposed well should be increased over that which is normal. Such inspections should occur at least weekly while drilling in the critical zone, and during the same period, Canterra shall report daily to the ERCB field office respecting its progress and any problems encountered.

19. The chances of a blowout at the proposed well would be greatly reduced when compared to historical statistics respecting sour gas blowouts because of the extra precautions to be taken and the special equipment to be used. Although a precise estimate of the chances of a blowout at the well is not possible, it would be small enough that the well licence application need not be denied because the well is a high-blowout-risk well.

20. If the well is drilled and an uncontrolled flow occurs, the well should be immediately ignited to convert the H_2S in the effluent to SO_2 which would be more widely dispersed. This action would significantly reduce the degree to which evacuations would be necessary.

21. Special ignition equipment and procedures proposed by Canterra would successfully ignite the effluent should a blowout occur.

22. If a partially controlled flow occurs at the proposed well but it is not completely out of control, the volume of gas being released is small, and human life is not being threatened, the operator would be given a time period to attempt to control the well prior to intentionally igniting it.

23. If the well is drilled, an emergency planning area with a radius of 8 km would be appropriate, but the area should be divided into three zones within which certain emergency actions would be required, depending on the zone.

24. Evacuation of residents should take place within 1 km of the well and sensitive individuals within 8 km of the well if a problem occurs during kick-control operations. Other residents within 4 km of

the well may, if they so desire, be voluntarily evacuated at the same stage; however, such evacuation would not be essential in terms of public safety.

25 A detailed emergency response plan is required and input from the public is essential during its preparation. The Board would be prepared to defray reasonable costs for an appropriate expert to advise the public of the Bergen area in this regard.

26 It is not appropriate prior to drilling a well to formulate plans for capping the well should a blowout occur; however, emergency planning with respect to the proposed well should be such as to ensure that control operations would be immediately commenced in the event of a blowout.

27 If the well proceeds and a blowout occurs, the impact of H_2S on the public would not be severe, provided the well is immediately ignited.

28 The SO_2 which would be emitted if the well blows out and is ignited would not have a significant impact on the surrounding area or its inhabitants.

29 A blowout at the proposed well would have little impact on surface or groundwater primarily because no condensate or liquid hydrocarbons are to be expected.

30 Late fall would be the time period during which a sour gas blowout at the proposed well would likely have the least impact on residents of the area. Adherence to a schedule that would accommodate that, in the unlikely event of a blowout, would not seriously delay the applicant in proceeding with the well.

31 The only particularly serious period at the proposed well would be while drilling in the critical zone when extra efforts are required to safeguard against a blowout. For this reason, efforts should be made to reduce the time period during which operations are taking place in the critical zone.

32 The applicant is a major, responsible Canadian corporation with very large resources and it undertook at the hearing to provide compensation for any damages it is responsible for. Consequently, there is not a specific need to require the posting of a performance bond or the carrying of special blowout insurance.

33 If the proposed well is drilled and a testing of the very sour zone is necessary, a separate application would be required. That application would have to detail procedures which would be used to minimize impacts of the tests on the public.

34 The successful drilling of the proposed well could lead to further developments in the area. These would be subject to further applications which would be considered on their merits at the time they are made.

14 DECISION

On the basis of the above listed findings, the Board concludes that the proposed well could be drilled without undue risk to the public, or impact upon it, provided the applicant implements drilling and emergency plans as discussed throughout this report. Many elements of Canterra's plans suitably provide for this, other areas require additional planning or modification, and the Board will condition the licence accordingly.

The Board is therefore prepared to issue the requested licence.

The following are the general areas where conditions will be applied:

1 Commencement of drilling will not be permitted if prior tests elsewhere in the province, of the proposed production technology, suggest little likelihood of it being successful.

2 Commencement of drilling will not be permitted until Canterra has submitted a final drilling program, which fully addresses, to the satisfaction of the Board, the areas identified in this report.

3 Drill-stem testing of the critical zone in the well will not be permitted unless a subsequent application demonstrates a clear need and that impacts on the public would be acceptable.

4 The operator will be required to provide daily reports of drilling progress, problems encountered, and other pertinent data to the Board's area office (Red Deer).

5 An uncontrolled flow at the well would require immediate ignition, and a partially controlled flow would only be allowed to continue without ignition where there is clearly no threat to human life.

6 Commencement of drilling will not be permitted until Canterra has submitted a final emergency response plan which fully addresses, to the satisfaction of the Board, the areas identified in this report.

7 The timing of and procedures used in the drilling of the well must be such that the time period during

which the critical zone is open would be minimized and limited to the months of October and November.

ISSUED at Calgary, Alberta, on 28 December 1984.

ENERGY RESOURCES CONSERVATION BOARD

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APPENDIX 1 GLOSSARY OF TERMS

ABSOLUTE OPEN FLOW POTENTIAL (AOFP)	The rate at which the well would (AOFP) produce against a zero sandface back pressure. It cannot be measured directly but may be obtained from deliverability tests. It is often used by regulatory authorities as a guide in setting maximum allowable producing rates.
ANNULUS	The space between two concentric pieces of pipe or between a pipe and the hole in which it is located.
ANNULAR PREVENTER	See BLOWOUT PREVENTER.
BATTERY	In oil and gas production, a group of wells which flow to a common central facility where production can be measured and separated into oil, gas, and water.
BARITE PLUG	A high density, pumpable slurry consisting of barite, water, and thinner used to control underground blowouts where high pressure flow comes into the wellbore from a lower zone while losses occur into a higher but weaker zone or vice-versa.
BLOWOUT	The uncontrolled flow of gas, oil, or other well fluids into the atmosphere. An UNDERGROUND BLOWOUT occurs when the uncontrolled flow leaves one formation and enters a lower pressure formation.
BLOWOUT PREVENTER (BOP)	The valve-like equipment attached to the casing at a drilling rig to prevent a blowout. The BOP STACK is a combination of these valve-like devices, piping, and other fittings. The uppermost valve is generally the ANNULAR PREVENTER which forms a seal in the annular space between the pipe and wellbore, or if no pipe is present, on the wellbore itself. The BLIND RAMS are a closing element which seal upon each other when no drill pipe is present in the hole. The PIPE RAMS are a closing element which seal upon pipe in the hole, thereby closing the annular space between the pipe and the blowout preventer or wellhead. SHEAR RAMS are closing elements which can cut through or shear drill pipe and form a seal against well pressure.
BUBBLE POINT	The temperature and pressure at which part of a liquid begins to convert to gas.
CALIPER LOG	See LOG.
CASING	The steel pipe placed in a well to prevent the collapse of the hole and provide a conduit for fluids during the drilling and production phases. The SURFACE CASING is the first string of casing set in a well after the conductor pipe. Some regulatory bodies require a minimum length to protect fresh water sands. The INTERMEDIATE CASING is a string of casing set in a well after some period of drilling beneath the surface casing. Its purpose is to prevent the hole from caving and is therefore sometimes called PROTECTION CASING. The last string of casing generally set in a well is the PRODUCTION CASING, inside of which is usually

	suspended the TUBING STRING through which production takes place. The entire length of the joints of casing run in a well is referred to as a CASING STRING. Casing is manufactured in lengths or JOINTS of about 10 metres (m), each of which is joined together to form the string.
CASING PATCH (EXTERNAL)	A mechanical device used to form a permanent sealed connection between two strings of casing or tubing. Generally, the patch is run into the well on the end of the running string of casing or tubing and grapples and seals onto the cut-off string in the hole.
CASING PATCH (INTERNAL)	A steel liner which is placed opposite a damaged or perforated section of casing or tubing and expanded to seal against the casing or tubing walls thereby effectively closing off the perforations. Alternatively, a casing patch may be a short section of liner which is set across the perforated section of casing or tubing and fixed in place with packers at either end of the patch.
CASING TIE BACK	A string of casing which connects the top of the liner to the wellhead, thus isolating the production casing from production pressures. A tie-back string may also be used in the case of production or intermediate integrity problems, such as corrosion, in order to ensure wellbore integrity.
CEMENTING	This is an operation in which a liquid slurry of cement and water is applied to various points inside or outside of the casing. PRIMARY CEMENTING takes place immediately after the casing has been run into the hole and is used to provide a protective sheath around the casing as well as to segregate the producing formation and prevent migration of undesirable fluids. SECONDARY CEMENTING is any cementing operation following primary cementing. A CEMENT SQUEEZE is an example of secondary cementing in which a cement slurry is forced under pressure to specified points in a well. It is used to isolate a producing formation, seal off water, repair casing leaks, and so forth.
CHOKE MANIFOLD	The arrangement of piping and chokes through which drilling mud is circulated to control pressures encountered during a kick.
CIRCULATING	The pumping of drilling fluids down the drill pipe, out through the drilling bit, up the annulus, and back to the mud tanks.
CLEAN-UP	The flowing of a well following a stimulation during which the stimulating agent, such as acid, is removed from the well and collected. Gas is flared to atmosphere and liquid products and waste are collected in stock tanks for removal.
CLOBBERED MUD (OR CLABBERED)	A slang term commonly used to describe moderate to severe flocculation of drilling fluid due to various contaminants; also called "gelled-up".

CONDENSATE	A light hydrocarbon liquid obtained by condensation of hydrocarbon vapours. It consists of varying proportions of butane, propane, pentane, and heavier fractions with little or no ethane or methane.
CONDITIONING MUD	See MUD CONDITIONING.
CORING	A drilling operation utilizing a core barrel instead of a drilling bit in order to obtain a cylindrical sample of formation rock for geological analysis. The CORE BARREL is a tubular device run at the bottom of the drill pipe in place of a drill bit in order to cut a CORE SAMPLE.
CORE BARREL	See CORING.
CORE SAMPLE	See CORING.
CRITICAL SOUR WELL	For blowout prevention purposes, a critical sour well is defined as follows: (a) any proposed well from which the maximum potential hydrogen sulphide (H_2S) release rate is greater than 2.0 cubic metres per second (m^3/s), (b) any proposed well from which the maximum potential H_2S release rate is greater than 0.3 m^3/s and less than 2.0 m^3/s if the well is to be located within 5 kilometres (km) (3.1 miles) of an urban centre,* or (c) any proposed well from which the maximum potential release rate is greater than 0.01 m^3/s and less than 0.3 m^3/s if the well is to be located within 1.5 km (0.93 miles) of an urban centre, or (d) any other proposed well which the Board classified as acritical sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area in which the well is to be located, and the expected complexities in the drilling of the well. * An urban centre is defined as a city, town, village, or other incorporated centre, and for the purpose of this directive includes any similar development the Board may designate as an urban centre.
CRITICAL ZONE	In drilling operations, the critical zone is a zone containing sour gas, generally the target formation. The ERCB's Draft Interim Directive – Blowout Prevention at Sour Wells addresses additional requirements while operations are taking place in the critical zone.
DEGASSER (POORBOY)	An open-bottomed steel vessel used to remove unwanted gas from a liquid, especially drilling fluid. The liquid enters the top of the vessel and passes down over a series of baffles which causes the entrained gas to break out of the liquid. The degassed liquid passes out of the bottom of the vessel

	into the mud tanks while the gas is vented from the top of the vessel to the flare pit where it is burned.
DRILL COLLARS	See DRILLING.
DRILL PIPE	See DRILLING.
DRILL-STEM TEST	The gathering of test data on a formation to determine its potential productivity. A drill-stem testing tool is lowered to bottom on the drill pipe and a packer is set which isolates the formation to be tested from the formation above. A port on the tool is opened to allow the trapped pressure below the packer to bleed off into the drill pipe, gradually exposing the formation to atmospheric pressure and allowing the well to produce to the surface, where the well fluids may be sampled and inspected. From the fluids produced and a record of the pressure readings, any number of facts about the formation may be determined.
DRILL STRING	See DRILLING.
DRILLER	See DRILLING.
DRILLER'S METHOD	One of several methods of well control used to circulate intrusive formation fluids or kicks out of the circulating mud system. This method of control may be used if the well can be closed in without exceeding the maximum allowable casing pressure (ie, the formation fracture pressure at the lowest depth at which casing is set). This method is advantageous in that it is simple, requires little calculation, and is effective under most conditions. In the first step, the original mud is pumped down the drill pipe at a constant pressure and the annulus is circulated free of invading fluids. If the hydrostatic pressure of the full column of drilling fluid does not overbalance the formation pressure, then a higher density drilling fluid is pumped into the well to replace the original, lower density drilling fluid.
DRILLING	The rotating of the DRILL STRING and bit and the circulation of DRILLING MUD to cause penetration of formations. DRILL STRING is a term often applied to the assembled lengths of DRILL PIPE and DRILL COLLARS. The DRILL PIPE is a heavy seamless pipe used to rotate the bit and through which the DRILLING FLUID or MUD is circulated. The DRILL COLLARS are heavier, thick-walled tube, usually steel, used between the DRILL PIPE and the bit in the DRILL STRING to place additional weight on the bit in order to improve its performance. The DRILLING MUD is the liquid circulated down the DRILL STRING and up the annulus during DRILLING. The procedure for DRILLING is laid out in a DRILLING PROGRAM prepared by the licensee of a well and containing instructions, diagrams, and other pertinent information. The employee directly in charge of a drilling or workover rig and crew is known as a DRILLER. His main duty is operation of the drilling and hoisting equipment but he is also responsible for the

	downhole condition of the well, operations of downhole tools, and pipe measurements.
DRILLING FLUID	See DRILLING, also see MUD.
DRILLING PROGRAM	See DRILLING.
DRILLING SPOOL	A spacer between components of the BOP stack, containing valved outlets.
EMBRITTLEMENT	The loss of a material's ductility, or ability to deform without fracturing. This is thought to be due to the absorption of hydrogen atoms into the material, usually in the presence of water and/or H_2S. Commonly referred to as HYDROGEN EMBRITTLEMENT, the various mechanisms include HYDROGEN INDUCED CRACKING (HIC), SULPHIDE STRESS CRACKING (SSC), and HYDROGEN BLISTERING.
FARM-IN	An agreement whereby the holder of a petroleum and natural gas lease permits another company to drill for and exploit petroleum and natural gas reserves under a number of specified conditions.
FLOW CHECK	A procedure carried out during drilling operations to confirm whether formation fluids are entering the wellbore. Generally, this involves observing to see whether the well is flowing on its own. Flow checks may be performed periodically or when any kick warning sign, such as gas-cut mud, is observed.
FLOW TOTALIZER	A device used to monitor the drilling fluid system and provide warning of potential blowout conditions either by an indication of a flowing well or of lost circulation.
FORMATION	A subsurface layer or deposit that is composed throughout of substantially the same kind of rock. The exerted pressure under which the formation splits is known as the FORMATION BREAKDOWN PRESSURE. The pressure required to break a formation must exceed the pressure exerted by the overlying rock. Fluids trapped within the pore space of the formation are also under pressure due to the overlying rock (or previously overlying rock). This pressure divided by the depth of the formation gives the FORMATION PRESSURE GRADIENT. A NORMAL GRADIENT is the pressure gradient of a column of salt water and ranges between 9 and 11 kilopascals per metre (kPa/m). An ABNORMAL or OVERPRESSURED FORMATION will have a gradient in the range of 11 to 16 kPa/m. A SUBNORMAL or UNDERPRESSURED FORMATION will have a gradient in the range of 5 to 9 kPa/m.
FORMATION BREAKDOWN PRESSURE	See FORMATION.
FORMATION, NORMAL	See FORMATION.
FORMATION, OVERPRESSURED	See FORMATION.
FORMATION PRESSURE GRADIENT	See FORMATION.

APPENDIX 1 (continued)

FORMATION, UNDERPRESSURED	See FORMATION.
GAS PLANT	An installation in which natural gas is processed to prepare it for sale to consumers. A gas plant separates desirable hydrocarbon components from the impurities in natural gas.
H_2S SCAVENGER	A material that deactivates any H_2S entering the wellbore.
H_2S TRIM	A general term used to indicate that a piece of equipment, which may be exposed to H_2S gas, is fabricated from H_2S resistant material.
HYDROSTATIC PRESSURE	The pressure exerted by a column of fluid such as the drilling mud in the wellbore.
ISOPLETH	An imaginary line surrounding a point of potential contaminant release, formed by joining points which under certain conditions and at different times could experience an equal contaminant concentration (similar to a contour line).
KICK	Any entry of water, gas, oil, or other formation fluid into the wellbore. It occurs because the pressure exerted by the column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation drilled. If prompt action is not taken to control the kick or kill the well, a blowout will occur.
KICK CONTROL	Procedures used to control and eventually prevent further influx of formation fluids into the wellbore, thereby preventing a potential blowout. Formation fluids that have entered the wellbore are removed and replaced with an uncontaminated mud of a suitable density. Examples of these procedures are the Driller's Method, the Wait and Weight Method, and the Concurrent Method.
KILL	Activities to stop or to prevent the threatened blowout of a well. Usually accomplished by the injection of dense fluid into the well. A TOP KILL refers to the pumping of high density mud down a wellbore without drill pipe in the hole.
KILL, TOP	See KILL.
LOG	A systematic recording of data, as from the driller's log, mud log, electric well log, or radioactivity log. Many different logs are run in wells being produced or drilled to obtain various characteristics of downhole formations. A CALIPER LOG is a record whereby the diameter of the wellbore is ascertained indicating undue enlargement due to caving in, washout, or other causes. The caliper log also reveals corrosion, scaling, or pitting inside tubular goods. A MUD LOG is a record of information derived from examination of drilling fluid and drill cuttings. A portion of the mud is circulated out of the hole past a gas detecting device and is also examined under ultraviolet light to detect the presence of oil or gas. The MUD LOGGER is the employee of the mud-logging company who keeps the mud log.

APPENDIX 1 (continued)

LOG, CALIPER	See LOG.
LOG, MUD	See LOG.
LOGGER, MUD	See LOG.
LOST CIRCULATION	The loss of drilling fluid from the wellbore into a very permeable formation.
MANIFOLD	See CHOKE MANIFOLD.
MUD	The liquid circulated down the drill pipe and up the annulus during drilling.
MUD, CLOBBERED	See CLOBBERED MUD.
MUD CONDITIONING	The treatment of drilling mud with additives to give to certain properties. To condition and circulate mud is to ensure that additives are distributed evenly throughout a system by circulating the mud while it is being conditioned.
MUD, DRILLING	See MUD, also see DRILLING MUD.
MUD LOGGER	See MUD.
MUD PILL	A small quantity of heavy drilling fluid pumped into the top section of drill pipe prior to pulling the drill pipe out of the hole. This permits the mud level inside the drill pipe to fall, permitting connections to be broken without mud inside the drill pipe at floor level. (Also known as "slugging the pipe" or a "dry trip".)
MUD, WEIGHTING-UP	The addition of materials with a high specific gravity to a drilling fluid in order to increase its density. This material is commonly barite, but may also be galena or limestone.
PARTIAL PRESSURE	The pressure exerted by one component of a gas mixture. The total pressure is the sum of the partial pressures of the individual components of the gas mixture, each considered as if it were the only gas present in the given volume.
PERMEABILITY	A measure of the ability of fluids to flow through rock.
PIPE RAMS	See BLOWOUT PREVENTER.
pH	The acidity or alkalinity of a fluid; a measure of hydrogen ion activity.
POROSITY	The void or open space in a rock.
POSITIVE PRESSURE AIR SUPPLY	A system used in the design of a breathing apparatus whereby the face mask is provided with an air supply of greater pressure than atmospheric pressure, to prevent infiltration into the mask of potentially harmful gases.
PRODUCTIVITY INDEX (PI)	A well-test measurement indicative of the amount of oil or gas a well is capable of producing.
RAW GAS	Naturally occurring gas prior to the removal of unwanted impurities at a gas plant.

RELIEF WELL	A well drilled near and deflected into a well that is out of control, making it possible to bring the wild well under control.
SEMI-DISPERSED	The condition in which the material or phase to be scattered or dispersed in a continuous or surrounding phase has not yet been completely dispersed.
SHEAR RAMS	See BLOWOUT PREVENTER.
SHUT IN	To close the valves on a well so that it stops producing or to close in a well in which a kick has occurred.
SKIN DAMAGE (SKIN EFFECT)	1. The area of the formation that is damaged because of the invasion of foreign substances into the exposed section of the formation adjacent to the wellbore during drilling and completion. 2. The pressure drop from the outer limits of drainage to the wellbore caused by the relatively thin veneer (or skin) of the affected formation. Skin is expressed in dimensionless units; a positive value denotes formation damage and a negative value indicates improvement.
SPOOL	See DRILLING SPOOL.
SPUD	To start drilling the wellbore.
STRIP INTO	The lowering of pipe, tubing, or coiled tubing into a well under pressure. In the case of a blowout, once the pipe is in the hole the well can be routinely killed using conventional procedures.
SUPERCRITICAL GAS	A dense phase vapour occurring at specific temperatures and pressures.
SWABBING	To cause a sucking action within the wellbore by pulling the drill pipe up the wellbore too quickly and accelerating or inducing the invasion of formation fluids.
TIE BACK	See CASING TIE BACK.
TOOLPUSH	A drilling foreman or rig superintendent.
TRIP	The process of pulling the drill string out of the hole or TRIP OUT, to change a drill bit or other bottom-hole equipment, and then lowering the drill string back into the hole or TRIP IN.
TRIP IN	See TRIP.
TRIP OUT	See TRIP.
TRIP TANK	A small calibrated mud pit used exclusively to ascertain the amount of mud necessary to keep the wellbore full with the exact amount displaced by drill pipe being removed.
TUBING	Small diameter pipe that is run into a well to serve as a conduit for the passage of oil and gas to the surface.

APPENDIX 1 (continued)

TUBULAR GOODS	Any kind of pipe; also called tubular. Oil-field tubular goods include tubing casing, drill pipe, and line pipe.
TUBULARS	See TUBULAR GOODS.
UNDERGROUND BLOWOUT	See BLOWOUT.
VISCOSITY	A measure of the resistance of a liquid to flow. The viscosity of petroleum products is commonly expressed in terms of the time required for a specific volume of the liquid to flow through an orifice of a specific size.
WELL EFFLUENT	The substances which flow out from a well.
WELLHEAD	The equipment used to maintain surface control of a well after it has been drilled and completed.

APPENDIX 2

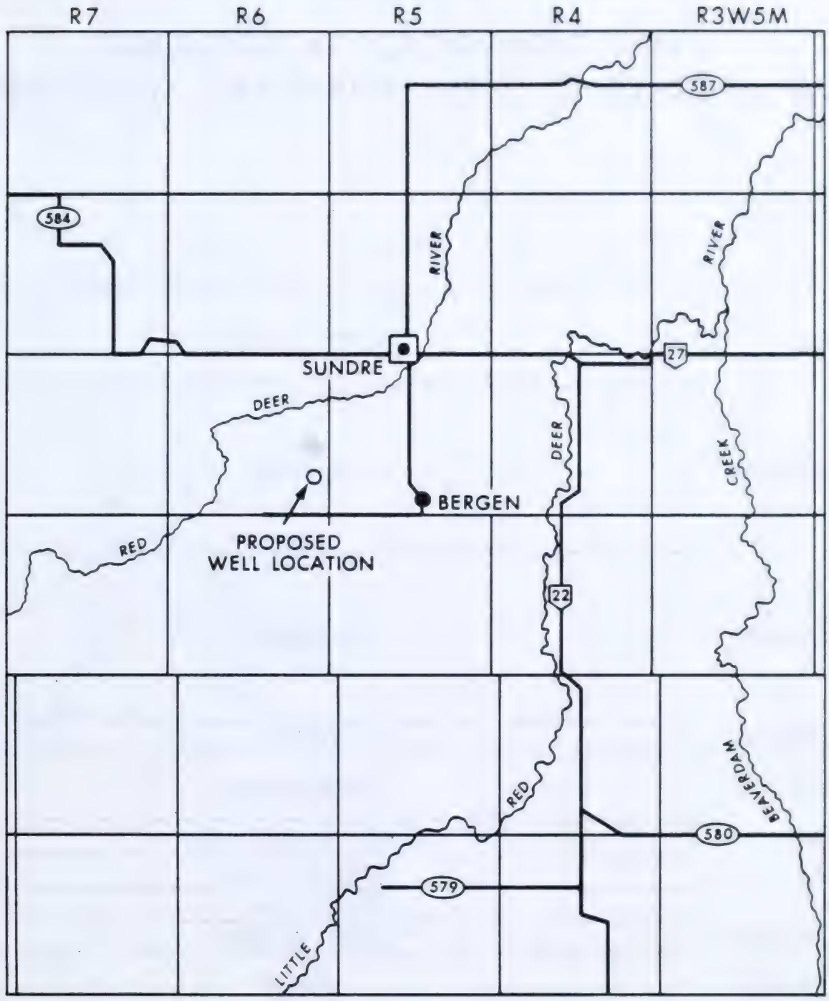

FIGURE 1 CANTERRA'S PROPOSED CAROLINE WELL IN THE SUNDRE - BERGEN AREA.

APPENDIX 3

GEOLOGICAL CROSS-SECTION
PROPOSED CANTERRA WELL 12-12-32-6 W5M

DEPTH		
1446	BELLY RIVER	SAND / SHALE
1726	WAPIABI	SANDSTONE / SILTSTONE
2302	CARDIUM	SANDSTONE / SILTSTONE
2778	VIKING	SANDSTONE / SILTSTONE
2846	BLAIRMORE	SANDSTONE
3069	MANNVILLE GROUP	SANDSTONE
3172	ROCK CREEK	SANDSTONE
3187	NORDEGG	LIMESTONE
3206	RUNDLE GROUP	DOLOMITE / LIMESTONE
3322	BANFF	LIMESTONE / SHALE
3522	WABAMUN	DOLOMITE / LIMESTONE
3798	NISKU	DOLOMITE
3853	IRETON	SHALE
3887	LEDUC	DOLOMITE
4087	COOKING LAKE	DOLOMITE / LIMESTONE
4137	BEAVERHILL LAKE	DOLOMITE / LIMESTONE
4237	ELK POINT	SHALE
4257	CAMBRIAN	DOLOMITE
TD – 4287		

APPENDIX 4

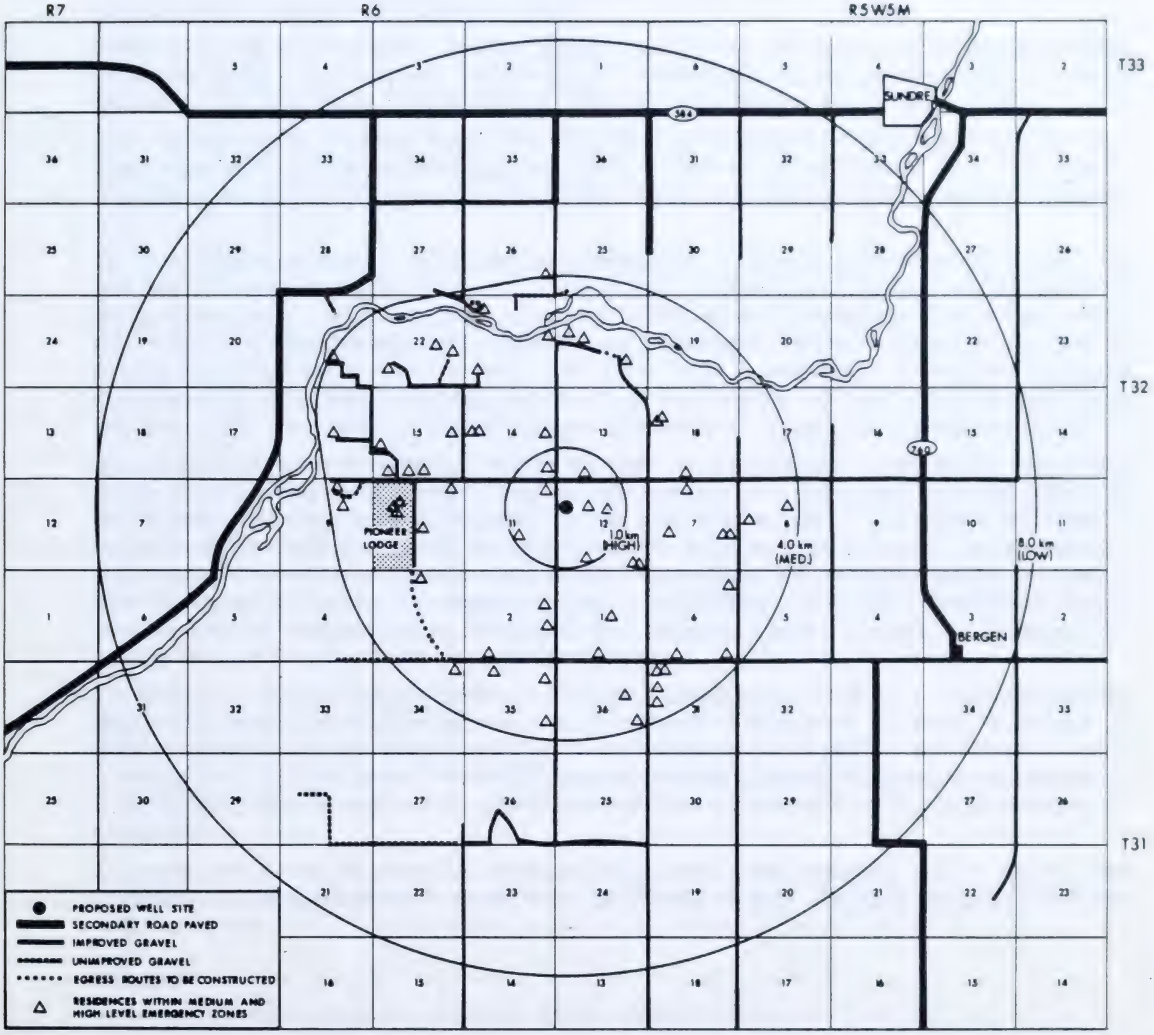

FIGURE 2 PROPOSED CANTERRA CAROLINE WELL IN THE SUNDRE AREA
Adapted from Appendix D, Canterra Caroline 12-12-32-6 W5M
Revised Emergency Alert and Evacuation Plan.

APPENDIX 5 DRAFT INTERIM DIRECTIVE ID 84-

To: All Operators, All Drilling Contractors,
and the General Public

BLOWOUT PREVENTION AT SOUR WELLS

Reference is made to the recently completed inquiry respecting the 1982 blowout at the AMOCO DOME BRAZEAU RIVER 13-12-48-12 well. The second phase of that inquiry was not related to the specific blowout but dealt with the broad subject of the prevention of blowouts in the Province as a whole.

There was considerable agreement among most participants on a number of the matters dealt with. One such matter related to the need for special safeguards against blowouts in the drilling of certain "critical sour wells" Discussion also took place respecting plans that would minimize impacts on the public should such a blowout occur.

The Board believes this matter to be of considerable importance and urgency and consequently is issuing this draft Interim Directive to define certain wells it considers to be "critical" and to establish requirements for the drilling of those wells. It recognizes that the special requirements will result in somewhat higher drilling costs for these wells but is convinced that these additional costs are warranted particularly having in mind that the potential cost of a blowout at one of these wells is very large. It should also be noted that the special requirements and related costs would apply only to a small portion of the total number of wells drilled in the Province. In 1983, fewer than 50 of the wells drilled would have been designated as "critical sour wells".

The Board intends that these interim requirements will apply for an approximate 6-month period, during which time the adequacy of them will be tested. Comments with respect to these requirements are invited prior to the end of October 1984, from industry, the public, and any other interested parties. The Board would expect to issue a new directive and, as necessary, amend the regulations at the end of the trial period, thus establishing a long-term policy respecting critical sour wells. At that time the Board will review and update, and combine where appropriate, its directives with respect to sour gas. (Interim Directive ID-OG-76-2, Emergency Procedure Plans For Sour Gas Facilities. Interim Directive ID 81-3, Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments.)

This draft Interim Directive is being included in the Phase 2 inquiry report. A task force or committee is being established to review certain of the matters discussed at Phase 2 of the inquiry. The Board believes that the committee should review the appropriateness of this draft directive and the policy it establishes, and should provide its comments by the end of October. If in the meantime and as a result of applying the requirements on an interim basis, particular problems or questions arise, the Board will refer such questions to the committee for its comments.

This interim policy does not change the minimum distance requirements separating sour gas facilities from residential and other developments as set out in Interim Directive ID 81-3. The policy respecting critical sour wells is as follows:

Definition

For blowout prevention purposes a critical sour well is defined as follows:

(a) any proposed well from which the maximum potential hydrogen sulphide (H_2S) release rate is greater than 2.0 cubic metres per second (m^3/sec),

(b) any proposed well from which the maximum potential H_2S release rate is greater than 0.3 m^3/sec and less than 2.0 m^3/sec if the well is to be located within 5 kilometres (3.1 miles) of an urban centre*, or

(c) any proposed well from which the maximum potential release rate is greater than 0.01 m^3 sec and less than 0.3 m^3/sec if the well is to be located within 1.5 kilometres (0.93 miles) of an urban centre, or

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* An urban centre is defined as a city, town, village, or other incorporated centre, and for the purpose of this directive includes any similar development the Board may designate as an urban centre.

(d) any other proposed well which the Board classifies as a critical sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area in which the well is to be located, and the expected complexities in the drilling of the well.

Special Requirements

The applicant for a licence for a critical sour well must satisfy the following special requirements:

1 A satisfactory emergency response plan must be filed with the Board prior to the spudding of the well. The plan must meet the minimum content requirements set out in ID-OG-76-2 and must describe the manner in which the public would be notified, have their safety protected, and be evacuated if necessary, in the event of a blowout. The plan must also have been discussed with members of the rural public and urban representatives that reside within the maximum 100 parts per million isopleth which could be associated with the well. It should also deal with the manner in which the decision would be made as to whether the well would be intentionally ignited in case of a blowout.

This requirement for an emergency response plan is in addition to those set out in ID-OG-76-2 for gas plants and pipelines. Also, pursuant to section 7.060 of the Oil and Gas Conservation Regulations, the Board may continue to request emergency response plans for certain wells which are not "critical sour wells" under this directive.

2 A general description of the drilling plan and the equipment to be used to drill the well must be submitted to and approved by the Board prior to the spudding of the well. The plan would include geological data as necessary but be general in nature and briefly describe any serious drilling problems which may be expected and the manner in which they would be handled. It should also briefly address critical equipment such as the BOPs (including a discussion as to whether or not shear rams will be installed), the drill string, the degasser, the mud system, and procedures, to ensure that all such equipment is fully operative prior to penetrating the critical zone. The plan should also provide for the taking of a directional survey unless the operator can satisfy the Board that it is not needed.

3 The operator must satisfy the Board prior to spudding that supervision during the drilling of the well will be adequate. This will require on-site supervisors with Level 2 certification and some experience in drilling in sour areas. During critical periods at the well, such as drilling into the sour formation, sufficient supervision must be available so that no individual supervisor is required to work a shift longer than 12 hours.

4 The operator must satsify the Board prior to spudding that the drilling crew and key service personnel on the rig are adequate in number and sufficiently qualified. A minimum 5-man drilling crew will normally be required and at least some of the personnel should have experience in sour areas.

5 The operator must satisfy the Board prior to spudding that adequate safety personnel and safety equipment for workers will be on site at all critical times.

6 Intermediate casing set to an appropriate point above the zone from which sour gas or oil is expected will normally be required. However, the Board may exempt certain wells from this requirement if the applicant can demonstrate with a high degree of certainty that intermediate casing is not warranted.

7 A complete inspection and blowout prevention drill will be required prior to drilling out the surface casing and the intermediate casing and before penetrating the formation expected to contain sour gas. The Board field office must be notified at least 48 hours ahead of time so that staff may participate if judged appropriate.

8 If the well is not abandoned, completion and servicing operations will not be permitted without prior consent from the Board. Consent will be granted only if the Board is satisfied that proper equipment and trained personnel will be used and that adequate precautions to prevent a blowout will be taken.

APPENDIX 5 (continued)

Additional Information to Support Well Licence Applications

The maximum potential H_2S release rate must be submitted as part of a licence application for any well and should be calculated on the basis of the maximum flow rate and H_2S content which can be expected. It should reflect all information available from wells in the area and a realistic engineering approach which recognizes the expected geological setting and reservoir fluid. A detailed description of the type of information required is set out in Attachment I.

Information respecting the maximum potential release rate along with plans for satisfying the above special requirements should be submitted with a licence application for any well which would be a "critical sour well" in accordance with the definition in this directive. In instances where the Board decides that a critical designation should be attached to a well which does not otherwise qualify in accordance with this directive, the applicant for a licence will be sent a deficiency letter requesting information to satisfy the special requirements.

The additional information provided the Board to determine the maximum potential H_2S release rate or to satisfy the above listed special requirements will, with certain exceptions, be considered as public information. Where geological data or personal information respecting individuals is provided as part of the submission, the Board will, upon request from the applicant, consider it as confidential. Such information should be included in a separate volume to avoid inadvertant release. In situations where a well licence application goes to a public hearing the matter can be decided on the basis of only that information which is public. However, the applicant will be provided with an opportunity to reclassify as public, all or a modified part of the data originally filed as confidential.

Comments regarding this directive from industry, the public, or other interested parties should be addressed to the Manager, Development Department (297-8169).

Applicants requiring further information regarding well licensing should address their inquiries to the Well Licensing Section (297-8159) and regarding emergency response plans to the Environment Protection Department (297-8324).

ISSUED at Calgary, Alberta on 25 April 1984.

Vernon Millard

Vernon Millard
Chairman

Attachment

ATTACHMENT I (ID 84-)

Where an application is made to the Board for a well licence, the applicant shall include in the application the information required in either A or B, as applicable.

A A statement and supporting evidence to the effect that none of the formations to be encountered during the drilling of the well are expected to contain hydrogen sulphide (H_2S).

or

B 1. For each formation to be penetrated which may contain H_2S:

   (a) the maximum expected concentration of H_2S, and the source of this information,

   (b) the maximum expected flow capability at the surface for the case where the unstimulated formation is open to the wellbore as during drilling, and for the case where the well has been completed and the formation stimulated, and the method and information used to determine these values,

   (c) the calculated potential H_2S release rate expressed in the units of cubic metres per second for each of the two cases referred to in (b) above.

2. The maximum potential uncontrolled release rate of H_2S at the stage in the drilling of the well where the sum of the release rates from each formation open to the wellbore is a maximum.

3. The maximum potential uncontrolled release rate of H_2S during the producing stage for the well.

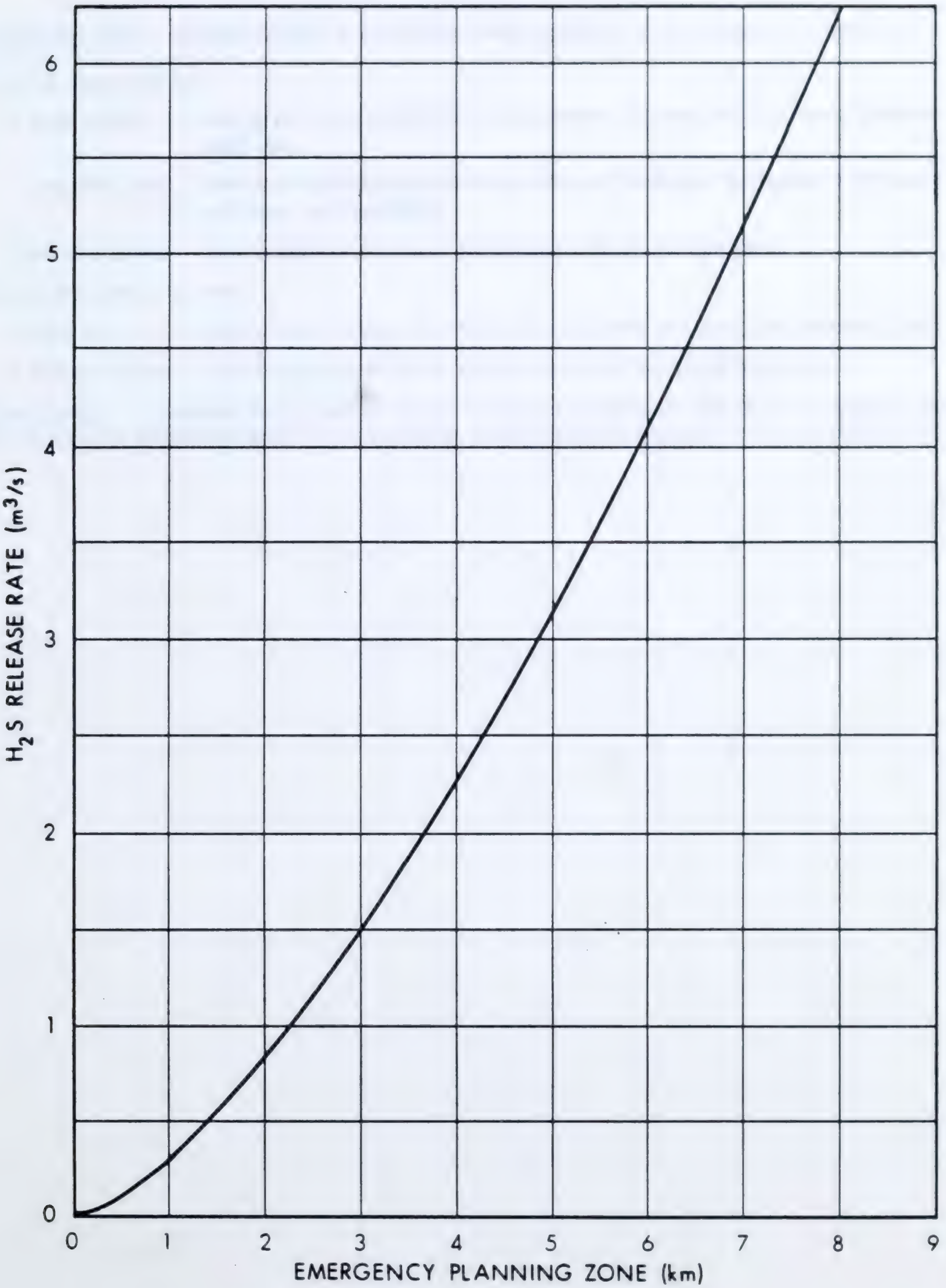
4. The radius of the emergency planning zone for each of 2 and 3 above, determined from the graph in Figure 1 to this Attachment.

5. A map showing the location of all residences and public facilities located within the larger of the emergency planning zones.

6. A statement of the distance to the nearest permanent residence, public facility, rural subdivision, or urban centre beyond the larger of the emergency planning zones, plus an indication of the population density in the general area beyond the planning zone a distance approximately equal to the radius of the planning zone.

It is emphasized that a realistic, responsible engineering approach must be taken. The expected geological setting and reservoir fluids to be encountered must be recognized along with all relevant tests and analyses for the area. In order that the best possible information be available all operators are urged to file the results of tests and analyses with the Board as soon as possible following the completion of the tests.

FIGURE 1 TO ATTACHMENT I
EMERGENCY PLANNING ZONES FOR SOUR GAS WELLS



APPENDIX 6 IGNITION CRITERIA

Uncontrolled Flow – unrestricted flow at surface that cannot be shut off at the operator's discretion, eg,

With drill pipe in the hole

- open annulus – flow up the annulus with BOP stack inoperative and pipe rams and annular preventer essentially open
- open drill pipe – flow up the drill pipe with stabbing valve not installed or inoperative in the open position and shear ram inoperative
- material failure – flow through cracks, seals, gaskets below the lowest pipe rams

With no drill pipe in the hole

- open well – flow up the wellbore with BOP stack inoperative and blind rams essentially open
- material failure – flow through cracks, seals, gaskets, etc, below the lowest blind rams

Partial Control – a restricted flow at surface of low volume which cannot be shut off at the operator's discretion but which can be approached safely by workers using suitable breathing apparatus, or can be safely flared.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

DEVNIC RESOURCES LTD.
APPLICATION FOR A WELL LICENCE
ACHESON AREA

Decision D 84-29
Application 840922

1 THE APPLICATION AND HEARING

Devnic Resources Ltd. applied for a licence to drill a well in legal subdivision 13 of section 18, township 53, range 25, west of the 4th meridian (the proposed well). The purpose of the proposed well would be to obtain gas production from the Belly River Group (Belly River) and oil production from the Ellerslie Member (Ellerslie) or the Wabamun Group (Wabamun).

The attached figure (Attachment 1) is a map of the area, all within the city limits of the City of Edmonton, showing the location of the proposed well, roads, and a utility right of way. It also identifies the residences and lands of those parties that intervened in the application.

A public hearing of the application was held in Edmonton, Alberta, at the office of the Energy Resources Conservation Board on 6 November 1984, with G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and H. J. Webber, P.Eng., sitting.

Interventions opposing the application were filed by Mr. and Mrs. R. D. Miller and by Grude's Management Consulting Ltd. and Mr. Jan Grude who are surface owners in the general area of application.

At the commencement of the hearing, a request by Mr. Grude for postponement of the hearing was denied by the hearing panel on the basis that Mr. Jan Grude had received adequate notice of the hearing.

2 THE ISSUES

The Board considers the issues with respect to the application to be:

- the need for the well,
- the impact of the well during drilling and production phases,
- mitigative measures taken to reduce impact, and
- future development in the area of application.

3 DEVNIC'S VIEWS

Devnic submitted that by virtue of a farm-out agreement with mineral rights owners, it had earned the right to explore for and exploit the reserves it believed underlie the northwest quarter of section 18, township 53, range 25, west of the 4th meridian. Devnic stated that the terms of the agreement stipulate the well must be spudded by 15 December 1984 and that the crown mineral lease on section 18, township 53, range 25, west of the 4th meridian, expires on 26 March 1985. The applicant further submitted that it had already had favourable contact with Norcen Energy Resources Ltd. with respect to the contracting of any potential gas reserves.

Devnic anticipated any gas produced from the Belly River to be sweet and any gas associated with oil production from the Ellerslie or Wabamun to contain concentrations of hydrogen sulphide (H_2S) of 0.36 per cent and 0.55 per cent by volume, respectively.

Devnic submitted that the drilling of the well should take approximately 2 weeks. Devnic stated it did not anticipate any problem in drilling and completing the well as none had been experienced at other wells it has drilled in the area, nor was it aware of any problems associated with activities of other companies operating in the area. Further, because of the concerns expressed by the interveners, and as a prudent operator, Devnic is prepared to take extra precautions to ensure no adverse impacts result from the drilling of the well.

With respect to the production phase of operations, Devnic stated that an exact determination of what facilities would be required is not possible until the results of drilling and testing the well are known. It said that it is prepared to take additional steps to reduce any real or perceived adverse impact the production of the well could have on the surrounding residents and area. Further, Devnic noted that approval of production facilities for the well would be the subject of additional applications to the Board.

Devnic submitted that even though the concentrations of H_2S which would be associated with the well are very small, it is aware of the local residents' sensitivity to the issue of H_2S and had taken steps to ensure a proper response to any and all problems which could arise. With respect to the drilling of the well, Devnic had already proceeded to implement additional safety steps by exceeding the require-

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Devnic Resources Ltd. (Devnic) S. R. Miller	T. M. Donhuysen Dr. D. M. Leahy R. W. MacDonald, P.Eng. R. E. Marshal
Mr. and Mrs. R. D. Miller (the Millers) G. Miller	R. D. Miller I. Miller
Grude's Management Consulting Ltd. and Mr. Jan Grude (Mr. Grude) D. H. Field	P. Juchli
The City of Edmonton (the City) W. Cameron	
Energy Resources Conservation Board staff C.J.C. Page J. R. Nichol, P.Eng. N. F. Lord, C.E.T.	

ments of Draft Interim Directive 84-[1] with respect to the planning radius, designing an Emergency Response Plan which it tabled as evidence at the hearing, and ensuring that all rig personnel and equipment could cope with an emergency should one arise. Devnic further submitted that with respect to producing and operating the well, it is prepared to equip the facilities in accordance with the conditions outlined on page 46 of the Board's West Edmonton Inquiry Report[2] with the exception that it would wish to truck oil off lease until it determined that sufficient reserves were present to facilitate a pipeline. The conditions are listed on Attachment 2.

Devnic stated it has other potential well sites in the area which it would plan to develop, depending on the results of the currently proposed well. It also stated that it would assume responsibility for any off-site damages that could be attributed to any of its operations at the site.

4 THE INTERVENERS' VIEWS

4.1 The Millers

The Millers stated that having read of a glut of oil on the world market, the necessity of drilling this specific well which, in their opinion, would "interrupt and disrupt the living of people in the area", was not apparent. They submitted that while the actual drilling of the well would be undesirable, that operation would be for a short duration and, therefore, their concerns were primarily with the presence of a producing well in the general area.

The Millers expressed a concern over sour gas emissions from the well site. They indicated that they have already experienced odours and smoke from other non-industrial off-site activities due to the natural airflow from the general direction of the proposed well site, through a valley in which their residence is located. Consequently, they believe that any emissions at the well site would be quickly transmitted directly to their residence. Noise and illumination from a flare stack were also of concern to the Millers.

The Millers stated that any well and associated equipment being built so close to their property line would result in devaluation of the property and would limit their land development possibilities for the future. They indicated that at present they had no definite development plans or schedule for the property, but did look upon the land as a financial resource during their retirement years ahead.

The Millers did accept Devnic's undertaking to be responsible for damages resulting from the well.

The Millers submitted that though they still objected to the well, the most acceptable scenario for producing the well would be one with a minimum impact on the surroundings, which would entail minimum structures, noise and odour levels, and acceptable esthetic values.

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[1] Appendix 5, Lodgepole Blowout Inquiry — Phase 2, Sour Gas Well Blowouts in Alberta: Their Causes, and Actions Required to Minimize Their Future Occurrences. Decision D 84-5 Proceeding 830007.

[2] ERCB Inquiry Report D 83-F Resource Development/Urban Development, West Edmonton Area.

The Millers further submitted that, in preparation for possible future problems, an inventory of biological and environmental factors of the area should be performed prior to the drilling of a well.

4.2 Mr. Grude's Views

Mr. Juchli, on behalf of Mr. Grude, stated that he was aware that for continued prosperity of the province, there must be development; however, if the well were to be approved, he would encourage the implementation of the conditions as set out on page 46 of the Board's West Edmonton Inquiry Report. This would, in his opinion, help alleviate concerns with respect to odour, noise, health, the environment, devaluation of property values, and the general esthetics of the area, even though he was still in general opposition to the proposed well.

4.3 The City of Edmonton's Views

The City of Edmonton (the City) submitted that it was appearing at the hearing in order to respond to any questions presented by the interveners or the Board and to reaffirm its position with respect to the well, as set out in its submission to the Board dated 25 June 1984[3]. It was the City's position that from its perspective and within the context of the Board's West Edmonton Inquiry Report, Devnic should be allowed to drill. It was the general position of the City to encourage the early economic depletion of resources prior to urban encroachment. The City submitted that in these matters it relied on the Board with respect to issues of health, safety, and quality of life, and would encourage individuals who have concerns to present their opinions to the Board.

5 BOARD VIEWS

The Board notes that the applicant has the right to explore for minerals in the lands in question. It believes that there is no practical means, other than drilling the property, to determine if reserves are present or to produce them if they are. For these reasons, the Board is satisfied that there is a need to drill the well, and thus would be prepared to license it provided there would be no significant negative impacts on the surrounding residents and the City.

The Board is of the view that the risk of and from a blowout at the proposed well would be very low, particularly having in mind the extra precautionary measures which would be taken during the drilling phase. These would include additional drilling supervisory personnel, a safety supervisor, and extra blowout prevention drills.

If a blowout did occur, the expected production rate and H_2S content for the well would be such that there would be no significant danger to residents of the area. The potential threat to residents would be further reduced as a result of the emergency alert plan formulated for residents within 500 metres of the well. In this regard, the Board, if it issues a licence for the proposed well, would require that the plan be submitted for approval by the Board prior to spudding of the well. The plan would have to address the following two measures in addition to those described at the hearing:

- The residents within the emergency planning zone (500 metres) would be provided with a handout describing the proposed location of the well, the characteristics and dangers of H_2S and sulphur dioxide, the evacuation procedures, and the telephone number of a company contact person.
- In the event of an emergency, evacuation of the residents within the 500-metre planning zone would be performed in person by company personnel.

The Board therefore accepts the mitigative measures as proposed by Devnic during the drilling phase and believes that the drilling of the well can proceed without significant impact on the surrounding area.

The Board has also analysed the potential adverse effects associated with the operation of a flowing or pumping oil well at the proposed site should a successful well be drilled. The Board notes that Devnic agreed to equip the well in accordance with the series of requirements outlined in Attachment 2, with the exception of the requirement that no trucking of oil and salt water be allowed. Although these requirements are designed for an urban residential setting, the Board does not believe that they are unreasonable for the subject well, and would require Devnic to satisfy those requirements, with the exception of item (g). In this case, the Board agrees with Devnic that the prohibition of all trucking operations would be inappropriate, at least until such time as sufficient reserves have been established to justify the installation of a pipeline. It is important to note that any production volume that would be too low to justify a pipeline would only constitute about one truck load per day.

Devnic has also undertaken, in response to the interveners' concerns respecting visual impact, to plant coniferous trees around the entire well site if the well is a successful producer.

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[3] Public Hearing — Well Licence Application Proceeding No. 840922.

There is no application before the Board for a specific type of production facility at the site. However, concerns were raised respecting the operation and potential impact of such a facility and the Board believes that it would be appropriate to make some comments respecting the matter. The installation of a production facility of any type or for any duration, temporary or permanent, would be the subject of a separate application and would be considered on its own merits at that time. The Board believes, however, that any application should have due regard for and be an integral part of an overall resource development plan for the area.

In addition, the Board would expect that even a temporary production facility would be a completely closed production system, including vapour gathering of all storage tank vapours and installation of an incinerator-type stack rather than the conventional oilfield flare stack.

With regard to the Millers' request that baseline environmental data be gathered before the well is drilled, the Board does not expect that the environmental impact of the proposed well would be such that it would be reasonable to require a study of this type. Should the Millers detect any impacts after the well is drilled, the Board would expect them to advise both Devnic and the Board's Edmonton Area Office and mitigative action would be taken.

With respect to possible future developments in the general area, additional wells and related facilities would be subject to future applications to the Board. The Board would expect that any applicant would be aware of the Board's West Edmonton Inquiry Report and that the approach to future development would be consistent with an overall resource management and development plan for the area.

6 DECISION

The Board is satisfied that Devnic has the mineral rights to the lands in question, there is a need for the well, and that the drilling and production of the well would not result in significant impacts on nearby residents or the City of Edmonton.

The subject application is therefore approved and a well licence will be issued in due course, subject to the conditions outlined herein.

DATED at Calgary, Alberta, on 30 November 1984.

ENERGY RESOURCES CONSERVATION BOARD

DeSorcy

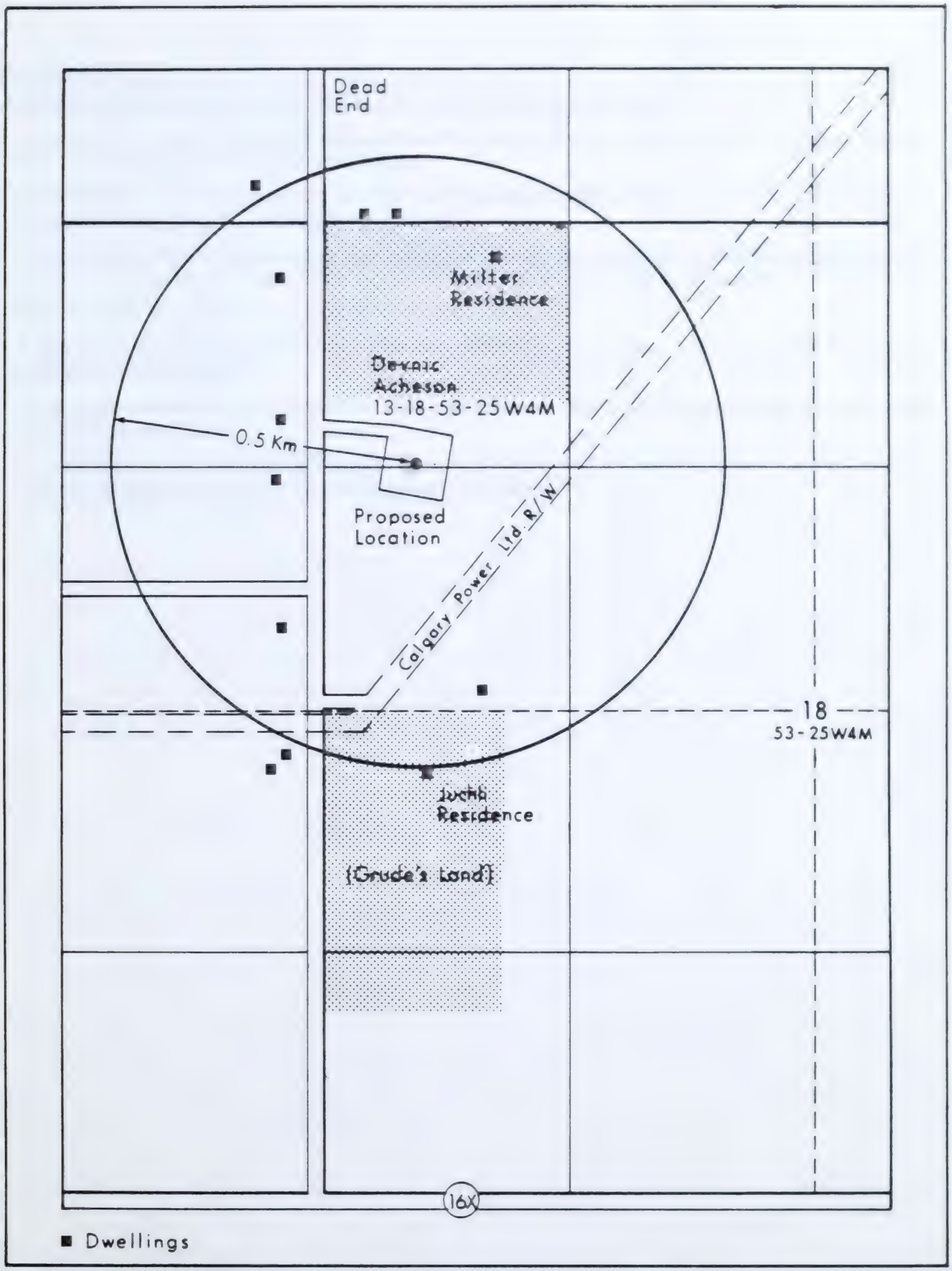
G. J. DeSorcy, P.Eng.
Vice Chairman

Bellows

L. A. Bellows, P.Eng.
Board Member

H. J. Webber
Acting Board Member

ATTACHMENT 1



DEVNIC'S PROPOSED WELLSITE APPLICATION NO. 840922

ATTACHMENT 2

(a) All wells would be equipped with high and low pressure shut-down devices.

(b) Pumping wells would be equipped with electric-drive motors and a blowout prevention device to shut off flow from the well in the event of a rod failure.

(c) Lease equipment would be limited to that absolutely essential for the operation of the well. In particular, no permanent flaring facilities installed at the well site.

(d) Wells must be properly fenced, including a locked gate. In addition to restricting unauthorized access to the site, the fence should be designed such that it will reduce the visual impact of the facility.

(e) Good housekeeping practices and regular painting are a must.

(f) A sign giving the company name and 24-hour telephone numbers to contact must be placed in a prominent place at each well location.

(g) Trucking of oil and salt water would be prohibited except in special circumstances and only with prior approval from the Board.

(h) Electrification of the well equipment must be in accordance with the neighbourhood electrical system, including underground wiring if such is being used in the area.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Interim Decision D 84-30
Application 840147
Proceeding 840350

BRAZEAU RIVER NISKU CARBONATE BANK
PRIMARY PRODUCTION AND CYCLING SCHEME

1 INTRODUCTION

Differing views between operators as to pool configuration, reservoir transmissibilities, and reservoir fluid properties led to different concepts of depletion strategy for the Brazeau River Nisku Carbonate Bank (Carbonate Bank) reservoir. Development of gas processing and gathering facilities in the absence of a common depletion strategy for the area's reserves resulted in the Energy Resources Conservation Board (Board) imposing restraints on the production of gas from Carbonate Bank wells. The restraints stipulated that no production was to be taken from these wells below their dew-point pressures prior to establishing the optimum depletion strategy for the area. The Board initiated common proceedings for a general inquiry into depletion of the Carbonate Bank and to hear an application by Amoco Canada Petroleum Ltd. (Amoco) for approval of a cycling scheme in a portion of the Carbonate Bank. (Proceeding 840350 and Application 840147, respectively.)

2 THE INQUIRY AND HEARING

The inquiry and hearing was opened in Calgary on 25 June 1984. Submissions indicated a wide range of interpretations regarding reservoir fluid dew-point pressures, pool configuration, and overall depletion strategies. Dew-point pressure measurements ranged from 27 255 kilopascals (kPa) in the well located at 7-34-47-12 W5M (7-34 well) to 30 233 kPa and 32 000 kPa in wells operated by Amoco and Petro-Canada Inc. (Petro-Canada), respectively. As the reservoir pressure was already at or near the apparent dew points of the Amoco and Petro-Canada wells, these companies opposed any primary production from the area. Dome Petroleum Limited (Dome) contended that the dew point of its 7-34 well provided a window for primary production from that well.

The inquiry and hearing was adjourned pending the results of a joint testing program designed to resolve some of the uncertainties. In its Memorandum of Decision, dated 18 July 1984, the Board deferred consideration of the cycling scheme and imposed a volume restriction on the primary production of gas to be permitted from the 7-34 well. The deferral and restriction reflected uncertainties in reservoir and fluid characteristics and the need for more information and regulated production from the area prior to establishing the optimum depletion strategy for the recovery of hydrocarbons. The Board agreed to a proposed 5-month testing program.

Dome, as operator of the 7-34 well, requested that the restriction be lifted and primary production be allowed to continue such that the 7-34 well pressure would not be reduced below the dew-point pressure. This request, based on the results of the testing program, was part of Dome's submission regarding Proceeding 840350. Amoco and Petro-Canada requested that the Board prohibit primary production of gas from the Carbonate Bank prior to commencement of the cycling scheme proposed by Amoco.

The inquiry and hearing reopened on 27 November 1984. Fluid analyses and pressure tests performed during the testing program provided a better interpretation of pool configuration and reservoir fluid dew-point pressures. Dome considered the reservoir fluid in the 7-34 well area to be represented by a dew point of 27 255 kPa while Petro-Canada considered the dew point of its wells in the 3-20-48-12 W5M (3-20 well) area to be 28 000 kPa. Amoco supported the dew point of 27 255 kPa for the 7-34 well.

3 VIEWS AND INTERIM DECISION OF THE BOARD

The Board agrees with the area operators that cycling is required to optimize recovery from the area, and therefore approves the principle set out in Amoco's Application 840147 that a cycling scheme be initiated. The Board believes that cycling should commence with the start-up of the Petro-Canada Brazeau River processing plant and completion of a unit agreement for the pool.

The Board concurs with the participants that the major uncertainties regarding the dew-point pressures in the reservoir have been reduced significantly as a result of the testing program. The Board has decided that a pressure of 27 300 kPa is a reasonable estimate of the dew point for the pool. It believes that an operating pressure of some 1500 kPa above the dew point would provide a suitable initial operating safety margin until a depletion strategy has been determined.

Given the lower estimates of dew points in the wells in communication with the 7-34 well, the Board believes that some primary production can be allowed in the Carbonate Bank without adversely affecting conservation. Primary production will not be allowed from a well whose extrapolated built-up pressure is less than 28 800 kPa. Pressures are to be determined and reported every 3 months from any well on primary production, incorporating the results of a build-up test not less than 2 weeks in duration. The Board expects the participants will not permit continuance of primary production, approved herein, to impede early commencement of cycling.

The Board will consider further the evidence of the inquiry and the application by Amoco. It will issue a detailed decision report on the operating parameters of the cycling scheme in the near future.

DATED at Calgary, Alberta on 13 December 1984.

ENERGY RESOURCES CONSERVATION BOARD

V E Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

PALMER RANCH (1984) LTD. INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA

Decision D 84-31
Application 841040

1 INTRODUCTION

Palmer Ranch (1984) Ltd. applied, pursuant to section 30 of the Oil and Gas Conservation Act (Act), for an industrial development permit authorizing the annual use of 128 million cubic metres of natural gas for the production of anhydrous ammonia in a plant to be constructed on the site of the decommissioned Pincher Creek gas plant. The ammonia plant would produce approximately 129 thousand tonnes of product per year, when operating at capacity. A 20-year permit term was requested.

A public hearing of the application was held in Pincher Creek, Alberta, on 5 and 6 December 1984, with V. Millard, V. E. Bohme, P.Eng., and T. F. Homeniuk, P.Eng., sitting.

The parties who appeared at the hearing are identified in the following table.

2 BACKGROUND

In January 1984, Palmer announced the signing of an agreement with Gulf to purchase Gulf's decommissioned Pincher Creek gas plant, a portion of its Pincher Creek gas reserves, and gathering and compression facilities. The agreement provided Palmer with access to a serviced site for the proposed ammonia plant, including road, rail, and utilities infrastructure. Gas formerly processed at the Gulf Pincher Creek plant is now being routed to the Shell Waterton gas plant after dehydration and compression at the present Palmer facilities. These operations would continue on completion of the proposed ammonia plant.

Gulf is committed to leaving the former Pincher Creek gas plant site in an environmentally safe condition, consistent with the land use proposed by Palmer. The reclamation measures undertaken by Gulf are being completed in several phases, in consultation and with the approval of Alberta Environment.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Palmer Ranch (1984) Ltd. (Palmer) K. F. Miller	M. N. Palmer T. R. Palmer W. J. Stenason S. A. DiNicolantonio D. H. Boyd G. P. Latonas Dr. W. S. Simmons Dr. D. M. Leahey
Pincher Creek and District Economic Development Board (Economic Development Board) K. Dickie	M. Tompkins
Gulf Canada Limited and Gulf Canada Resources Ltd. (Gulf) J. D. Anderson	
Western Co-Operative Fertilizers Limited (Western Co-Op) M. A. Putnam, Q.C.	

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THOSE WHO APPEARED AT THE HEARING cont'd

Principals and Representatives (Abbreviations used in Report)	Witnesses
Oldman River Regional Planning Commission (Planning Commission) W.C.H. Fischer	W.C.H. Fischer
Pincher Creek Area Environmental Association (Environmental Association) D. P. Mallon R.E.P. Clavier	S. Taylor D. Blackburn D. McGlynn
Municipal District of Pincher Creek No. 9 (Municipality) H. R. Pharis	H. R. Pharis
Blood Tribe F. Martin	
Alberta Environment S. Dobko P. Shewchuk	
Energy Resources Conservation Board staff C.J.C. Page Dr. H. F. Thimm D. D. Fraser M. E. Mumby	

3 ISSUES

The Board considers the main issues to be:

- availability of feedstock,
- efficient use of gas,
- viability of the project,
- environmental impacts, and
- socio-economic or cost/benefit assessment.

4 AVAILABILITY OF FEEDSTOCK

Palmer stated that the combined feedstock and fuel requirements of the proposed ammonia plant would be 128 million cubic metres of gas annually. This volume assumes normal operation during 355 days of each year. Over the requested 20-year permit term, the total volume required would be some 2.6 billion cubic metres. The Board believes that sufficient gas would be available for the proposed project, but notes that gas supply arrangements have not been concluded. Palmer would therefore be required to advise the Board of satisfactory arrangements for the supply of gas, in the event that a permit is issued.

5 EFFICIENT USE OF GAS

Palmer proposes to use natural gas as feedstock and fuel in two conventional ammonia process trains which, although several years of age, remain unused and in storage. Process steps would include gas desulphurization, primary and secondary steam reforming, high and low temperature carbon monoxide shift conversion, carbon dioxide removal, methanation, and ammonia synthesis. The process units would be modified to include a heat recovery system at the primary reformer furnace. Waste heat would be utilized in subsequent sections of the process trains. Approximately 121 gigawatt hours of electrical energy would be required annually, mostly for synthesis gas compression.

The Board recognizes that the process units would provide efficiencies slightly lower than "state-of-the-art" technology, however, it notes that Palmer is committed to improving the efficiency of the process units to an economically optimal level. The Board is, therefore, satisfied that the level of efficiency of energy use would be acceptable.

6 VIABILITY OF THE PROJECT

Palmer submitted that the proposed project is economically viable as a result of several factors. A secure marketing contract has been entered into with Cargill Incorporated of Minneapolis, Minnesota, to sell essentially all of the output from the project into U.S. markets. Palmer also stated that it is in the final stages of securing a 5-year supply of natural gas feedstock for the project, and that firm prices would protect the project during the initial high-risk payout stage. It also stated that lower overall capital costs for the project would result from its location on the decommissioned gas plant site, which provides existing off-site infrastructure including road and rail transportation and electric power.

The Board is satisfied that the proposed project would be economically viable.

7 ENVIRONMENTAL IMPACTS

Applicant's Views

The applicant stated that no adverse ecological impacts are expected from the operation as a whole, and committed to giving area residents access to monitoring results. Palmer proposed to discharge some 708 cubic metres per day of wastewater into Drywood Creek, but is investigating the feasibility of disposing all or part of this wastewater to an irrigation system.

Maximum allowable ground level concentrations of nitrogen dioxide (NO_2) are not expected to be exceeded, in spite of the expected downwash from the reformer stacks during some meteorological conditions. Evidence was given to the effect that secondary pollutant formation is expected to be insignificant, that synergistic effects of pollutants should not be anticipated, and that Alberta's ambient air standards are more stringent than levels currently accepted elsewhere in North America.

Interveners' Views

The Municipality supported the application, but recommended the gathering of air and water quality baseline data prior to plant start-up, and suggested that adequate environmental monitoring systems be put in place to check the baseline data following plant start-up.

The Planning Commission expressed concerns about leaching of harmful chemical substances into Drywood Creek via the existing drainage course. It drew attention to the proximity of one residence to the proposed plant, and recommended that the diked area near the proposed ammonia tanks be hard surfaced to avoid leaching of spilled ammonia.

The Environmental Association, in direct evidence, recounted past experiences and concerns with sour gas operations in the area, and expressed uncertainty about the cumulative effects of emissions and possible secondary formation of new pollutants. It further suggested that the planned Medical Diagnostic Review (M.D.R.) for the region might be jeopardized by adding to the pollution load in the area at this critical time.

While not opposing the application, the Environmental Association asked that the licence to operate be subject to the following conditions:

- that an emergency plan be developed,
- that area residents be given access to all environmental monitoring data,
- that a "zero discharge" policy for wastewater be enforced (possibly by means of irrigation disposal) or, in the alternative, that discharge take place in such a manner that pollutants could not leach out of the existing drainage channels,
- if the "zero discharge" policy cannot be implemented, that the point of discharge to Drywood Creek be upstream of the water intake,
- that the applicant be required to co-operate closely with the M.D.R. team, in order not to jeopardize the study,
- that there be extensive mobile monitoring for airborne pollutants emitted by the proposed plant, and
- that, in the event of a plant expansion, an application to the Board be required.

Board's Views

The Board has noted the concerns of the Environmental Association regarding the formation of secondary pollutants, adequacy of ambient standards, and potential health effects. While the Board generally accepts the evidence of Dr. Simmons in these matters, it does concur with the Environmental Association and the Municipality that monitoring of air and water, both before and after start-up of the plant, would be appropriate. The Board does not believe that the operation of the proposed plant would interfere with the M.D.R., since it understands that the data for this study would be gathered during the period prior to plant start-up. Should the proposed project be approved, the Board would require monitoring of air, soil, and water by the applicant prior to and for some time after plant start-up. This could provide additional useful information to the M.D.R. study team.

The Board believes that monitoring should be carried out in consultation with area residents. If a permit for the proposed project were issued it would convene a meeting of interested parties, following which details of the monitoring program would be worked out. This group might also assist Palmer in developing an emergency plan and provide a means for dissemination of the monitoring data, in accordance with Palmer's undertaking.

With respect to questions of leaching of pollutants and wastewater disposal the Board notes that alternative techniques for wastewater disposal are presently under investigation, and that this matter would be the subject of a licence under the Clean Water Act. The Board sees no merit in imposing a discharge location as requested by the Environmental Association.

In view of the nature of the soils at the plant site, the Board does not believe that hard-surfacing of the diked storage tank area would be necessary.

8 SOCIO-ECONOMIC EFFECTS OF THE PROJECT

Palmer stated that construction of the project would begin in March 1985, would be completed by November 1985, and that over this 8-month period the average on-site work force would be 120, with a peak work force of 200. Upon completion of the project the operational work force would be comprised of approximately 48 full-time employees. Palmer submitted that the total capital expenditure on the project would be $34 million, 50 per cent of which would be spent in Alberta.

It appears to the Board that the construction schedule proposed by Palmer is reasonable, and that the beneficial economic impacts to be derived during the time of construction would be maximized by proceeding with the project during the current economic lull. Longer-term benefits accruing to the Pincher Creek area would be rendered through replacement of the industrial base lost through closure of the Gulf gas plant, as well as through diversification of the regional economic base. The Board believes that the Albertan and Canadian content of the project should be maximized to the extent practicable.

The Blood Tribe expressed concerns at the hearing regarding availability of employment and service contract opportunities for Tribe members. Palmer indicated that it would provide equal opportunity to all local residents, including members of the Blood Tribe.

The Economic Development Board, the Planning Commission, and the Municipality were all supportive of the proposed project, stating that economic benefits would spin off into the local area.

Annual operating expenditures are estimated to be $18.4 million, essentially all of which would be distributed into the Alberta economy. Annual revenue of the project is expected to be $40.4 million, generating Provincial tax revenue of $2.75 million and Federal tax revenue of $5.5 million annually. Palmer indicated that the total direct and indirect impact of the project over its 20-year life would be in excess of $1 billion.

The Board believes that the effects of these expenditures would have positive implications for the local and Provincial economy.

9 DECISION

The Board believes that the project would be in the public interest of Alberta, and that it would not have serious environmental or health implications. The Board is therefore prepared to issue the requested permit on the approval of the Lieutenant Governor in Council, subject to the conducting of special environmental monitoring as determined appropriate following discussions among Alberta Environment, Palmer, the Environmental Association, other interested parties, and the Board; the results of such special monitoring to be made available to area residents.

DATED at Calgary, Alberta, on 28 December 1984.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

Bohme

V. E. Bohme, P.Eng.
Board Member

Homeniuk

T. F. Homeniuk, P.Eng.
Acting Board Member

* FORM OF PERMIT

IN THE MATTER of the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Palmer Ranch (1984) Ltd. authorizing the use within Alberta of gas produced in Alberta for the production of anhydrous ammonia

INDUSTRIAL DEVELOPMENT PERMIT NO. MNP 85-1

WHEREAS Palmer Ranch (1984) Ltd. has applied to the Energy Resources Conservation Board for an industrial development permit, pursuant to section 30 of the Oil and Gas Conservation Act, authorizing the use of gas produced in Alberta for the production of anhydrous ammonia in Alberta; and

WHEREAS the Board, upon inquiry into the application, is of the opinion that the granting of this industrial development permit for the use of gas as raw material and fuel for production of anhydrous ammonia is in the public interest, having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrocarbons in Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered O.C. and dated , has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas

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* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Palmer Ranch (1984) Ltd. (hereinafter called "the Permittee") authorizing the use of gas as raw material and fuel for production of anhydrous ammonia, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. This permit is for the use in Alberta by the Permittee of gas as raw material and fuel for the production of approximately 129 000 tonnes per year of anhydrous ammonia, generally as described in the application to the Board dated 2 October 1984.

2. The plant facilities at which anhydrous ammonia will be produced shall be located in the southern half of Section 23, Township 4, Range 29, West of the 4th Meridian.

3. Subject to compliance by the Permittee with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on 31 January 2006.

4. The quantity of gas that may be used in the industrial operation referred to herein shall not exceed 128 000 000 cubic metres per calendar year.

5. The quantities of gas for the purpose of this permit shall be on the basis of a gas free of water vapour and having a higher heating value of 37.4 megajoules per cubic metre.

6. All gas used in producing anhydrous ammonia pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volumes of gas used as raw material and as fuel and of anhydrous ammonia produced shall be separately reported to the Board in a manner satisfactory to the Board.

7. The Permittee shall obtain the approval of the Board of any major changes in design of the plant facilities.

8. (1) The Permittee shall satisfy the Board, prior to 15 March 1985, or such other date as the Board upon application by the Permittee may stipulate, that arrangements for the financing of its proposed project have been completed.

(2) The Permittee shall satisfy the Board, prior to 15 May 1985, or such other date as the Board upon application

by the Permittee may stipulate, that construction of its proposed facilities has commenced and will continue in accordance with a schedule approved by the Board.

(3) The Permittee shall satisfy the Board, prior to 1 November 1985, or such other date as the Board upon application by the Permittee may stipulate, that arrangements for the supply of the necessary gas volumes have been completed.

9. During construction of the industrial operation referred to herein, the Permittee shall report to the Board semi-annually in a manner satisfactory to the Board with respect to the progress of construction.

10. The Permittee shall operate the facilities in a manner that results in

(a) the maximum practically obtainable efficiency in the use of gas for the manufacture of anhydrous ammonia, and

(b) the maximum practical conservation of gas.

11. The Permittee shall conduct such environmental monitoring as may be required by the Board and Alberta Environment, and the information obtained from such monitoring shall be made available to area residents upon request.

12. The Permittee shall not

(a) assign this permit, or

(b) release from his control the operation of the plant,

without the consent in writing of the Board, which consent may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

13. (1) Attached hereto as Appendix A, and made part of this permit, is the Order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council set out in Appendix A.

14. Where it appears to the Board or the Lieutenant Governor in Council that the Permittee has contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

15. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

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